A Forecast of Cost Effectiveness

Avoided Costs and Externality Adders

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TABLE OF CONTENTS

List of Tables

List of Figures

1.0 Executive Summary

1.1 Project Overview

This report presents the results of work performed by Energy and Environmental Economics, Inc. (E3) for the California Public Utilities Commission (CPUC) to forecast avoided costs and externality adders for use in cost-effectiveness evaluations of energy efficiency (EE) and demand-side management (DSM) programs.

1.1.1 Project Goals and Approach

The CPUC's goals in authorizing funding for this work were to:

- Establish a forecast for the years 2004 – 2023 of avoided energy costs for use in quantifying the benefits of demand-reduction programs.

- Establish a forecast for the years 2004 – 2023 of externality adders for use in quantifying program benefits,[1] specifically:

    - ***An environmental externality adder***, which has been a part of CPUC cost-effectiveness calculations in recent years and which "attempts to quantify…the negative impact on the environment, or cost to society resulting from the generation of electricity and the direct combustion of natural gas." (RFP, p. 4)

[1] The CPUC's "California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects" designates five types of cost-effectiveness tests for programs, each of which captures the costs and benefits of a program from a different perspective. The Total Resource Cost Test: Societal Version (TRCSV), in attempting to measure the costs and benefits from the perspective of society as a whole, allows for the inclusion of externalities.

- ***A transmission and distribution (T&D) adder***, also a part of recent CPUC cost-effectiveness calculations, which captures incremental demand-related capital expenditures, line losses and maintenance costs associated with increased energy use.

- ***A system reliability adder***, which includes the cost of maintaining a reserve margin.

- ***A price elasticity of demand adder***, which recognizes that reduced demand results in a decrease in the market-clearing price for electricity and therefore an increase in consumer surplus.

In addition to producing the deliverables described above, E3's methodology produces avoided cost estimates that are transparent and can be easily updated. This report documents a straightforward costing methodology that is implemented using a spreadsheet model and publicly available data. The spreadsheet model is sufficiently flexible to allow CPUC Energy Division staff to update the avoided cost estimates to reflect changes in the major cost drivers, including the price of natural gas, the costs of new generation, and the expected load-resource balance year in California.

Second, E3's estimates of avoided costs reflect the expected future costs to California energy consumers of purchasing more or less energy. The electric and gas utilities in California depend on electricity and gas markets to manage at least a portion of their energy needs. Our 2004-2007 forecasts of the avoided costs of energy reflect forward market prices for electricity and gas to be delivered at various points inside California. Our recommended methodology for the calculation of "adders" is also consistent with market price data. For example, our estimates of the reliability adder reflect historical market prices for ancillary services. As well, our estimates of a modest externality adder are based only on emissions costs not already included in the market prices for energy.

Finally, E3's methodology incorporates a number of forecasting methods and results used by the California Energy Commission (CEC). For example, E3's long-run avoided cost proxy for electricity generation uses the CEC's estimated costs of owning and operating a combined-cycle, gas-fired generator. We also make use of the CEC's long-run forecast of gas prices, which we use to develop long-term estimates of gas avoided costs. While alternative data sources are available, we believe that the CEC products are reasonable and provide unbiased estimates of future energy costs.

The CEC's commissioners recently supported incorporating new "Time Dependent Values" (TDV) of avoided costs into the Title 24 building standards beginning in 2005.[2,3] We made use of a large portion of the TDV methodology and data to develop area- and time-specific (ATS) estimates of transmission and distribution (T&D) costs.[4] The methodology captures significant differences in avoided costs due to weather, local capacity-demand conditions, and investment plans at times of peak demand.

Table 1 displays how we have incorporated ATS dimensions of the various avoided costs and adders into our methodology and results. Electric T&D costs vary by utility service territory, planning division and by the 16 CEC Title-24 climate zones used in the CEC's TDV study. The

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[2] Title 24 refers to the Energy Efficiency Standards for Residential and Nonresidential Buildings established in 1978.
[3] See http://www.energy.ca.gov/2005_standards/

costs of electricity generation and of natural gas procurement, transportation, and delivery vary by utility service territory because such costs do not vary by weather zone. Finally, the estimated costs of environmental externalities, maintaining reliability and the benefit multipliers resulting from price elasticity of demand are uniform across the state.

In addition to variation by area, the estimated avoided costs also vary by time. The avoided costs of electric generation, transmission, and distribution vary by hour, whereas the costs of natural gas procurement, transportation, and delivery vary by month. The price elasticity of demand estimate varies by time-of-use (TOU) period and by month. The cost of maintaining reliability is calculated as annual percentages applied to the hourly energy cost values. The costs of environmental externalities are computed by multiplying the emissions rate of the assumed marginal plant in each hour by a forecasted cost of each pollutant (CO_2, NOx, and PM-10).

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[4] E3 was the contractor responsible for estimating the avoided costs in the CEC's TDV project.

Table 1: Time and area dimensions of avoided costs and externality adders

Avoided Cost Stream	Time Dimension	Area Dimension
Avoided Electricity Generation	Hourly	Utility specific
Avoided Electric Transmission and Distribution	Hourly	Utility, planning area and climate zone specific
Avoided Natural Gas Procurement	Monthly	Utility specific
Avoided Natural Gas Transportation and Delivery	Monthly	Utility specific
Environmental Externality Adder	Annual value, applied by hour according to implied heat rate	System-wide (uniform across state)
Reliability Adder	Annual value	System-wide (uniform across state)
Price Elasticity of Demand Adder	TOU period (on- vs. off-peak) by month	System-wide (uniform across state)

Any forecast of avoidable electricity and gas costs over a long time horizon will be subject to uncertainty in the underlying cost drivers. Our study addresses this uncertainty in two different ways. First, even though the avoided cost estimates are used for programs with relatively long lives, we recommend frequent updates to the forecasts, perhaps as often as once per year, to reflect changes in important cost drivers. Thus, we have provided a spreadsheet-based model that allows input assumptions to be changed and updated by CPUC staff as conditions warrant. Second, we have developed a separate set of avoided costs for a *stress case* scenario characterized by high gas prices and poor hydro conditions. These avoided costs aim to capture the additional value that dispatchable resources can provide under stress case conditions.

1.1.2 Inclusive Process and Transparent Methodology

In completing the work described herein, E3 sought to develop a transparent and fully documented methodology using readily or publicly available data, so as to allow independent review by numerous stakeholders. The methodology and data that we used to forecast each avoided cost stream are described in detail in corresponding sections of this report. We have included an electronic data appendix containing all the electronically available source data so that interested parties may verify or contribute to our results.[5]

In addition, our approach has been open and inclusive throughout the development of these recommended avoided cost values. Our team's efforts to develop a sound analytical process benefited directly from the close collaboration and valuable input of the CPUC, CEC, California's four investor-owned utilities (IOUs), and the Natural Resources Defense Council (NRDC).[6]

In developing our avoided cost forecasts, our team progressed through the following steps from August through December 2003:

1. Five meetings attended by the parties mentioned above. Each meeting focused on the proposed methodology for a specific avoided cost or adder, as listed below. Feedback

[5] Certain data were only available in hardcopy filings. They include San Diego Gas & Electric's electric transmission data (from SDG&E's March 2003 FERC filing) and certain of Southern California Gas and SDG&E's gas T&D data (from their 2005 BCAP filings).
[6] The IOUs that participated in the review process were: Southern California Edison (SCE), Pacific Gas & Electric (PG&E), San Diego Gas & Electric (SDG&E), and Southern California Gas (SoCal Gas).

was welcomed during and after each meeting, and E3 modified the methodologies accordingly.

- Meeting 1, August 22, 2003. Topic: Proposed T&D Avoided Cost Methodology
- Meeting 2, August 29, 2003. Topic: Proposed Generation Marginal Cost Methodology
- Meeting 3, September 12, 2003. Topic: Proposed Environmental Adder Calculation Methodology
- Meeting 4: September 19, 2003. Topics: Proposed Natural Gas Avoided Cost Methodology and Proposed Reliability Adder Methodology
- Meeting 5: September 26, 2003. Topic: Proposed Price Elasticity of Demand Adder Methodology

2. Presentation of preliminary results (November 7, 2003) for the avoided cost components, followed by another comment period.

3. A written Draft Report (at hand) with results, detailed descriptions of methodologies, and data. This will be followed by yet another comment period.

4. A Final Report with software incorporating comments, with delivery targeted for the end of this year.

1.1.3 Summary of Different Viewpoints on the Recommended Costing Approach and its Applicability

Although public workshops are scheduled for January 2004 to facilitate comments on the Final Report and its applicability prior to the use of these avoided costs in 2005, all project participants recommended the inclusion of a brief description of the substantive comments provided on our results and methodology.

The participant's comments focus on nine issues addressed separately below.

1. ***Is the application of the 2004 avoided cost estimates limited to the evaluation of efficiency programs?***

In the past, the CPUC has used avoided cost estimates for a variety of applications, including cost-effectiveness evaluations of energy efficiency and utility planned investments, payments for Qualifying Facilities, and in ratemaking. A number of parties expressed a concern that the avoided costs developed here would be used in applications beyond the evaluation of efficiency programs.

The costing methodology and data used in this report were intended to reflect the most recent publicly available estimates of market-based avoided costs by hour and location for both natural gas and electricity. They do not incorporate proprietary data from each utility's short- or long-term procurement plans. For example, this report assumes that each utility has an average residual net short position of 5 percent between 2004, the first year of our forecast period, and 2008, the assumed resource balance year.

In the review of our work to develop a reasonably accurate 20-year forecast of avoided costs for energy efficiency programs, participants agreed that the general assumptions we made based on publicly-available data were sufficiently accurate for energy efficiency evaluation. While this specific agreement may not extend to other marginal costing applications, the recommended costing methodology is sufficiently general that future updates could include utility-specific proprietary data potentially allowing for more wide-ranging application of the results.

2. Is there a need to create a separate value of capacity in the avoided costs?

No. The avoided cost forecast is for firm delivered energy by hour to a specific voltage level and location. It does not include a separate value for capacity. Several participants requested that we create a separate value of capacity that could be used for dispatchable resources or even as a replacement for the combined-cycle plant that we use for the long-run avoided cost proxy. However, a separate capacity value was not required to evaluate efficiency programs and is beyond the scope of this project.

E3 has developed a separate module to estimate the avoided costs of dispatchable programs. The methodology calculates the optimal dispatch of a time-limited dispatchable program given the hourly energy, transmission, and distribution values. The use of hourly values provides an appropriate valuation that includes both energy and capacity elements. Program values can be developed using either the expected long term base-case results E3 recommends for evaluating non-dispatchable efficiency programs, or from the five specific natural gas price and hydro cases described in Section 4, the *Dispatchable Resources & Scenario/Stress Case Analysis* section of this report.

3. What is the right costing methodology for T&D avoided cost estimation?

There are comments on two issues related to Marginal Transmission and Distribution Avoided Capacity Costs (MTDCC). The first issue is related to the methodology used to compute MTDCC and the second issue is related to the appropriate use of the MTDCC values. All parties agree that methodologies that appropriately use forward-looking, "load growth-related" avoided costs based on the deferral value of T&D investments are appropriate. Such methods include the Present Worth Method, the Discounted Total Investment Method. Our team computed the MTDCC numbers using these approaches and a third approach called the Total Investment Method and found little difference in the MTDCC results for each approach.

On the appropriate use of MTDCC, the concern was raised that the MTDCC values would be applied to programs that are unlikely to impact transmission and distribution system investments in capacity. We believe that the proposed set of avoided costs addresses this issue by disaggregating the avoided costs by climate zone and hour. The MTDCC values are allocated to specific hours within each climate zone based on hours of extreme weather, which is highly coincident with local transmission and distribution peak loads. Programs that are expected to reduce loads during these hours should result in MTDCC benefits. Programs that achieve energy savings in hours that are not coincident with the climate zone peaks will not receive any MTDCC value. Therefore, multiplying the hourly program impacts by the appropriate hourly avoided costs will result in the appropriate allocation of MTDCC. The same result can be achieved if the proposed avoided costs are aggregated by TOU period, rather than by hour. In this case, the program impact coincident with local peak load would be estimated (in kW) and multiplied by the annual MTDCC value (in $/kW-year). Again, programs that do not achieve load reductions on peak would not receive any MTDCC value.

4. What level of aggregation of the cost estimates would be most useful?

Participant opinions differed over the benefit of different levels of aggregating location-specific avoided costs. One participant suggested that a statewide forecast would be a simple and useful approach to setting the avoided costs for statewide programs that might not be able to accurately estimate where the efficiency products or practices would be used. Although with the appropriate weighting, a statewide forecast could be easily produced, it is important to note that no single statewide forecast is suitable for all energy efficiency programs. For example, a statewide program targeted at the agricultural industry would result in different location-weighted avoided costs than one targeted at residential users. Another participant recommended that statewide programs receive no MTDCC benefit because the effect of the programs on individual transmission or distribution facilities would likely be so diluted that the programs would have no impact on deferring marginal infrastructure upgrades.

5. What is the appropriate discount rate to use for these avoided costs: the utilities' weighted average cost of capital, or a much lower social discount rate?

A comment was made that the discount rate used to compute the present value of expected future avoided costs over the life of the program was too high. The discount rate used for this purpose was a nominal 8.15%, which is based on the discount rate used in the current avoided costs from the Findings of Resolution E-3519. This is a policy decision and E3 does not have an opinion on the appropriate discount rate. However, we have structured the avoided cost calculation so that this value can be easily updated should a new discount rate be adopted.

6. Can the avoided costs be easily modified to account for a new resource adequacy requirement?

Yes. While the avoided costs methodology does incorporate a substantial reserve margin beyond what is currently maintained by the California Independent System Operator, the costing methodology can be easily modified to reflect any changes. For example, if a new standard requires additional capacity purchases beyond what is already included in the estimate, an adder could be included based on the cost of a simple-cycle combustion turbine. Alternatively, if these standards are implemented in the bilateral energy market, they can be reflected as multipliers to the long-run cost proxy, which is the cost of a combined-cycle plant.

7. Do the estimates of avoided costs include the "hedge value" that efficiency programs provide?

Yes. The avoided cost estimates over the next four years are derived from electricity forward market price quotes and NYMEX gas price futures prices that reflect the expected future spot price of electricity plus any risk premium. The avoided cost estimates beyond four years reflect the full cost of owning and operating a combined-cycle, gas-fired generator, which includes a price risk hedge that is at least as valuable as the hedge provided by efficiency programs.

8. Should the avoided costs of mitigating CO2 emissions be included as a DSM benefit?

Several participants questioned whether it was appropriate to include the costs of CO_2 emissions in the avoided costs for efficiency programs. Other participants supported the report's rationale for including the cost of CO_2 emissions. Another participant asked if we had considered using a *damage cost* approach for developing CO_2 cost estimates.

Unlike criteria pollutants such as NOx and PM-10, which are regulated under the federal Clean Air Act and corresponding state legislation, CO_2 is not consistently regulated at either the federal or state levels. We recognize that CO_2 costs are not included in the marginal cost of producing electricity or thermal energy from natural gas today, and that CO_2 is strictly an unpriced externality. However, the CPUC has indicated that it expects to address the potential financial risks of CO_2 in the avoided cost methodology in this proceeding; this direction is included in the finding of facts in each of the three proposed decisions in Rulemaking 01-10-024. It states: "We should refer the question of potential financial risks associated with carbon dioxide emissions to R.01-08-028, to be considered in the context of the avoided cost methodology -- as part of the overall question of valuing the environmental benefits and risks associated with utility current or future investments in generation plants that pose future financial regulatory risk of this type to customers."[7]

Given the 20-year time frame of this avoided cost analysis, we consider it highly likely that CO_2 will be regulated and become part of the marginal cost of using fossil fuel during the time period of the analysis.

9. Should Demand Reduction Benefits be included as avoided costs for efficiency programs?

Finally, two participants questioned whether Demand Reduction Benefits should be included in avoided costs. The demand reduction multiplier that we developed from historical data estimates a multiplier to be applied to avoided generation costs. The economic rationale of this requirement is that demand-side-management (DSM) and energy-efficiency (EE) programs reduce the electricity demand of program participants and shift the market demand curve

[7] California Public Utilities Commission, Proposed Decision of ALJ Walwyn, Rulemaking 01-10-024, November 18, 2003, Findings of Fact #64, pp. 223.

downward along a given market supply curve, thus effecting a price reduction that can benefit all electricity consumers.[8]

The benefit is, in economic terms, a "transfer" of wealth from suppliers to consumers that is attributable to efficiency programs. Although its inclusion in avoided cost estimates does not result in any gain in economic efficiency, reduced market prices result in lower utility procurement costs, which are certainly a benefit from a consumer's point of view. As such, we recommend including this benefit in short-run avoided cost estimates for peak period hours between 2004 and 2008. Once California reaches resource balance in 2008, the avoided cost of generation becomes the full cost of a new combined-cycle generator, rather than market purchases, in which case a multiplier is no longer appropriate.

1.2 Aggregated Results & Comparison with Existing Values

The results of our team's efforts are avoided costs forecasts disaggregated by area and time for both electricity and natural gas from 2004 through 2023. For electricity, we calculated the avoided costs by hour for each year for the 16 climate zones, 24 electric utility planning divisions, and 3 service voltage levels. This produces separate avoided cost estimates for customers served at each voltage level (transmission as well as primary and secondary

[8] A system demand reduction can decrease market prices in three specific and important ways. First, it reduces the output from units with high marginal production cost that drives the price offers of those units. Second, it can mitigate capacity shortages, thus diminishing the above-marginal-cost markup (i.e., shortage cost) required to balance system demand and supply. Third, it can counter energy sellers' market power, the ability to raise market prices through capacity withholding.

distribution levels). For natural gas, we have calculated the avoided costs by month for each year, utility, and customer type.

For example, Figure 1 shows the levelized electric avoided costs by month and hour for PG&E's San Jose Planning Division in Climate Zone 4, secondary voltage.[9] Climate Zone 4 includes portions of the San Jose, Central Coast, De Anza and Los Padres planning divisions. The vertical axis in Figure 1 shows the total avoided cost in levelized $/MWh. During the highest cost period for San Jose, the total avoided costs peak at approximately $225/MWh around 1-3 pm in late July, August and early September due to the allocation of T&D costs. In contrast, the avoided costs are less than $50/MWh in the early morning in the spring.

[9] The spreadsheet produces a database that includes estimates of avoided costs for each hour of the year for the next 20 years. This set of data is maintained for the CEC defined climate zones.

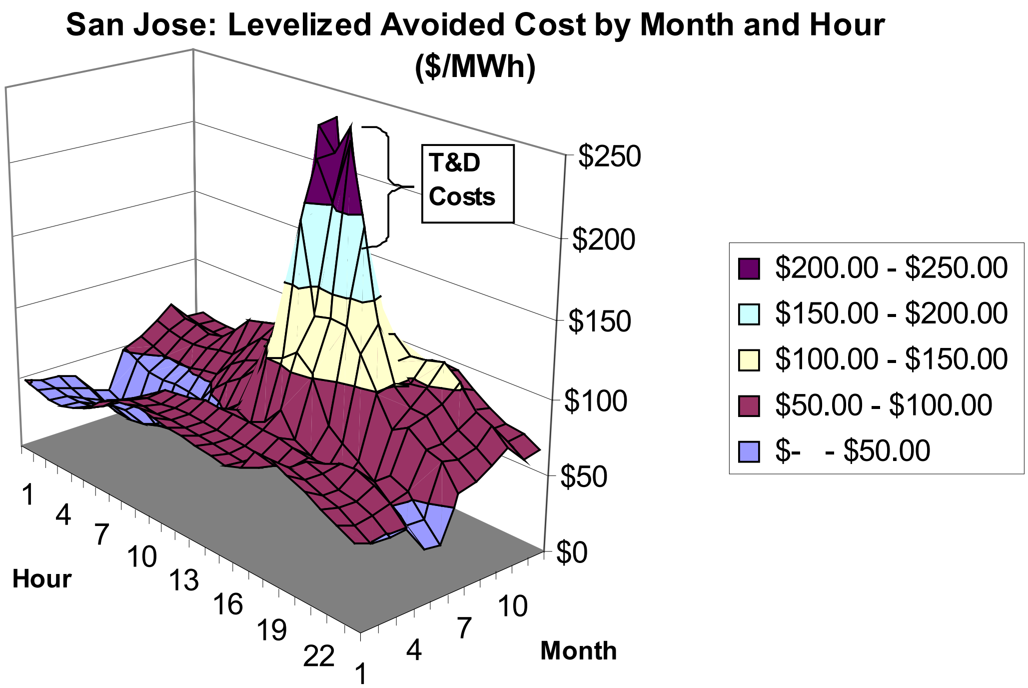

Figure 1: Electric avoided cost by hour and month for PG&E's San Jose Planning Division, Climate Zone 4, secondary voltage

Whereas the new forecast avoided costs vary by both area and time, the CPUC's existing avoided costs for evaluation of programs funded by the Public Goods Charge (PGC) specified in the CPUC Energy Division *Energy Efficiency Policy Manual* (hereafter referred to as *Policy Manual)* are annual, statewide forecasts.[10] Figure 2 shows the approximate range of the new levelized avoided cost values by planning division and service voltage level for 2004-2023

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[10] California Public Utilities Commission, *Energy Efficiency Policy Manual, Version 2*, Energy Division, August 2003, San Francisco, CA. This version updates Version I, prepared in October 2001, by extending the 2001 forecast, which ended in 2021, out to 2023.

compared to the CPUC's existing value.[11] The figure shows that most of the new avoided costs for customers served at primary and secondary service voltage fall between $70 and $75/MWh. As a result of our disaggregation of costs, the new avoided costs at the transmission service level do not include distribution avoided costs; therefore, they range from $63/MWh for SDG&E to $65/MWh for PG&E and SCE's service territories. The corresponding value for the CPUC's existing all-in levelized forecast is about $80/MWh, which is higher than all of the new forecast values and about 10% higher than the mode of the new primary and secondary avoided costs.

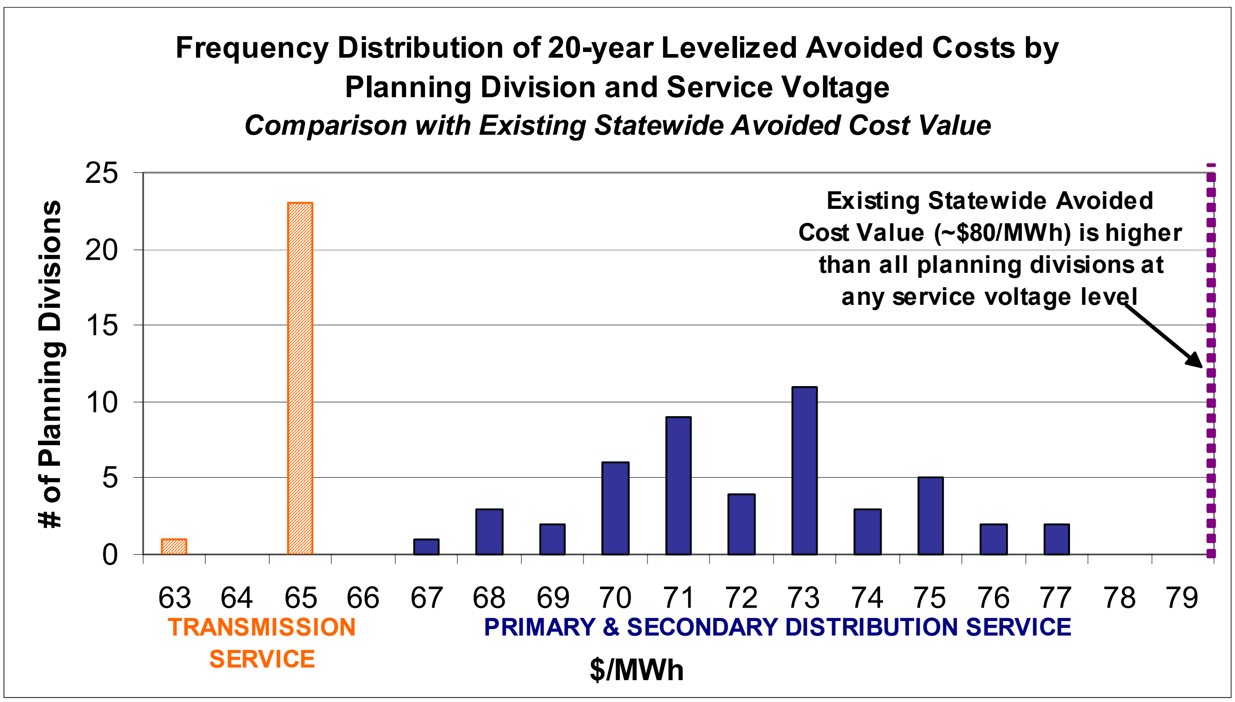

Figure 2: Histogram showing new levelized electric avoided costs (2004-2023) by planning division and service voltage when compared to exisiting statewide avoided cost value

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[11] For comparison purposes, we have excluded the 2002-2003 data from the CPUC's existing forecast because they do not overlap with the new forecast period and the 2002 data is abnormally high due to the California energy crisis.

Figure 3 compares our new forecast of annual average electric avoided costs for the San Jose Planning Division (secondary service voltage) to the existing avoided costs. We have chosen San Jose to illustrate the comparison because its levelized avoided cost falls into the $73/MWh bracket, the mode of the primary and secondary distribution of Figure 2. Although the costing data and methodologies are substantially different, our new annual forecast for San Jose is remarkably close to the CPUC's existing forecast for the same period, even though the CPUC prepared its forecast immediately following the California Energy Crisis.[12] One of the primary differences is that the CPUC's existing forecast grows at a faster rate than our new forecast over the long run.

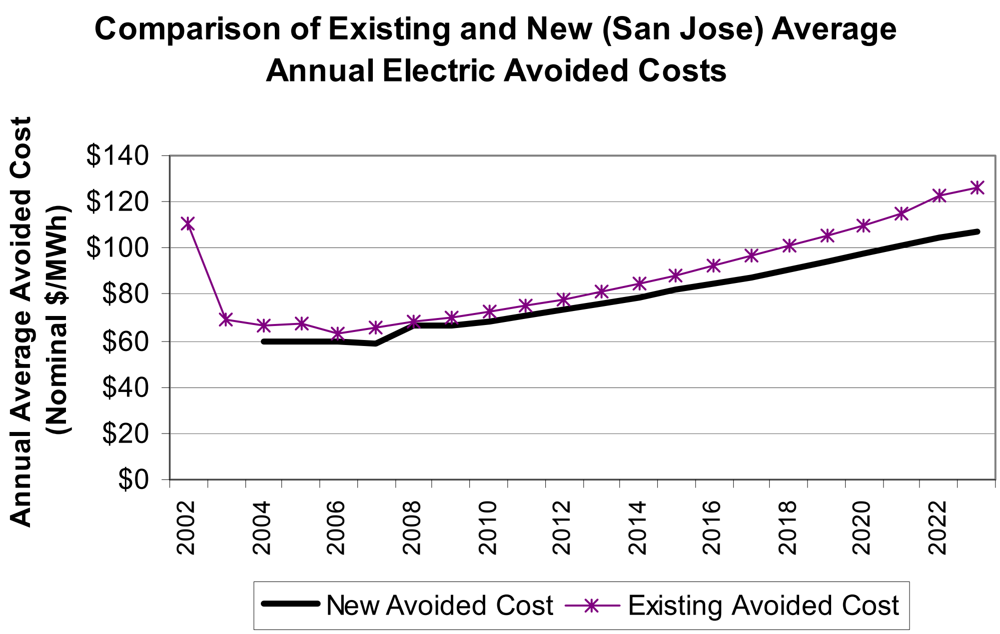

Figure 3: Comparison of existing and new electric avoided costs (new costs are for San Jose, Climate Zone 4, secondary voltage)

[12] The CPUC prepared the existing values for 2004-2021 in October 2001. In August 2003, it issued an update that extended the first forecast out through 2023.

One of the most significant differences in the electricity cost drivers is the forecast of natural gas prices. Figure 4 below shows historical gas prices delivered to PG&E Citygate, SoCal Gas and Henry Hub over the last seven years. The cost of gas has approximately doubled since the end of the energy crisis in August 2001.

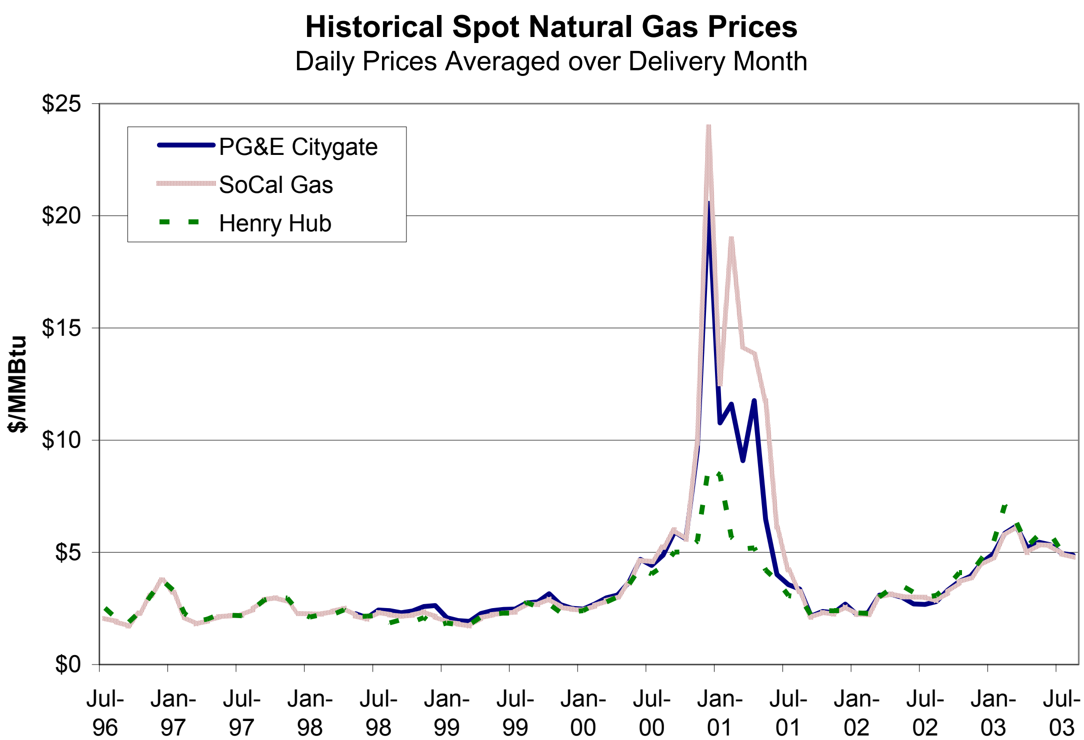

Figure 4: Spot natural gas prices (averaged over the delivery month) for July 1996 through July 2003. California prices spiked to unprecedented levels in December 2000, and remained high for the first half of 2001.

Figure 5 illustrates the difference between the CPUC's existing, statewide avoided costs of natural gas and E3's annual levelized forecast for one gas customer. In this example, which is based on SoCal's commercial rate for a large boiler with uncontrolled emissions and levelized at

8.15%, our forecast avoided costs of gas are higher than the existing values for every year in the forecast period.

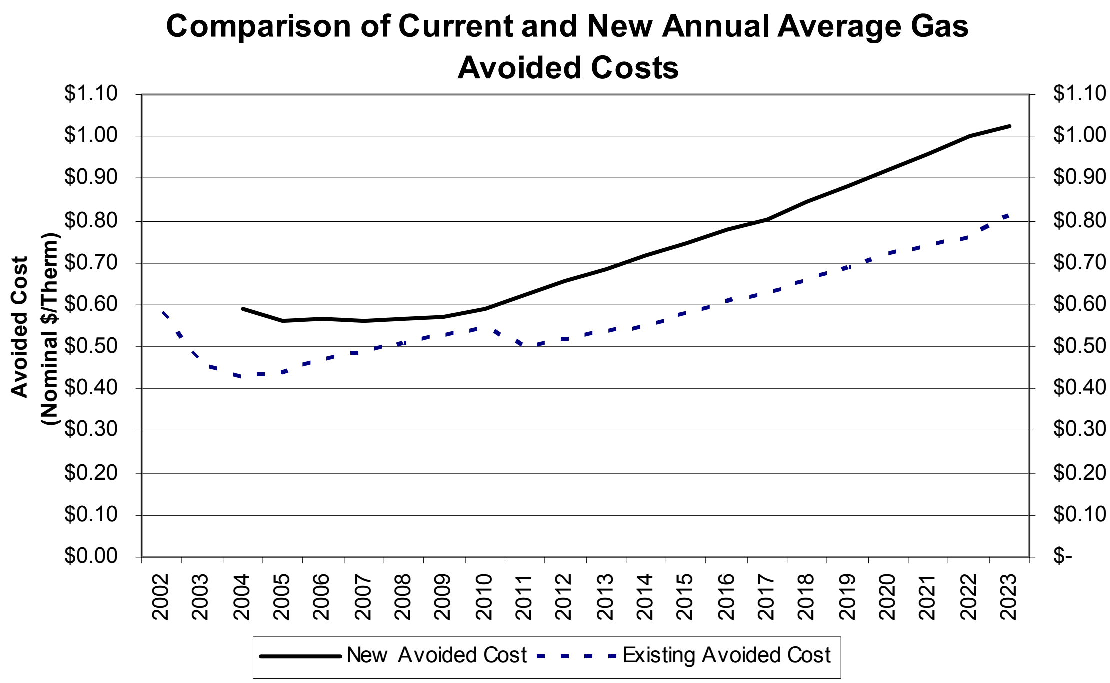

Figure 5: Comparison of existing and new avoided costs of gas for SoCal commercial customer (large boiler, uncontrolled)

In Figure 6, we show an example of the proposed estimates of natural gas avoided costs for a commercial customer taking service from SoCal Gas, relative to the existing avoided costs. The vertical axis shows the levelized avoided costs in $/therm. The flat horizontal line of $0.54/therm is the 20-year levelized value of the existing avoided costs. The higher, curved line represents the monthly levelized shape of the new avoided costs. We allocated all the T&D costs in the new avoided costs to the winter period (November through March). In combination with the higher commodity costs in the winter months, the new avoided costs are about $0.22/therm higher than the current annual average savings values. In the summer months, the new avoided costs are approximately $0.06/therm higher. It is clear that the new levelized costs are higher than the existing values in all months of the year.

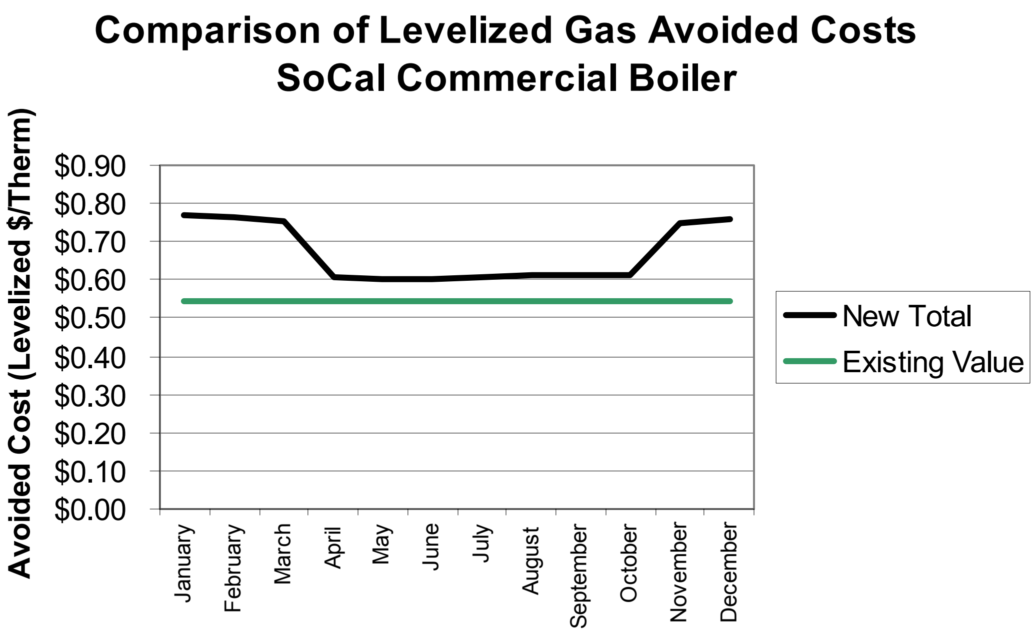

Figure 6: Comparison of levelized gas avoided cost by month for SoCal Gas commercial customer (large boiler, uncontrolled)

When we compare the average avoided costs by year, the new avoided costs are lower than the existing values for electricity, and approximately 25% higher overall for natural gas. However, with the disaggregation to time, energy efficiency measures that conserve energy during the high-cost hours or months have considerably more value than those during low-cost hours.

In Figure 7, we compare the results for three example electricity efficiency measures for secondary voltage customer in PG&E's Climate Zone 12 (the Central Valley area, including portions of the Diablo, Mission, North Bay, Sacramento, Stockton, Sierra and Yosemite Planning Divisions). The three efficiency measures are air conditioning, outdoor lighting and refrigeration programs. The air conditioning measure (upgrade of a residential A/C unit from 12 to 13 SEER) has an avoided cost savings of $138/MWh with the new avoided costs compared to a savings of approximately $78/MWh under the existing avoided costs. The large differential in avoided costs under the two forecasts exists because the majority of the savings in an A/C upgrade occurs during the summer peak period when the value is highest. In contrast, the value for outdoor lighting efficiency drops under the new avoided costs from $78/MWh to approximately $60/MWh. Refrigeration, which is assumed to have a flat energy savings profile, remains about the same under both sets of avoided costs.

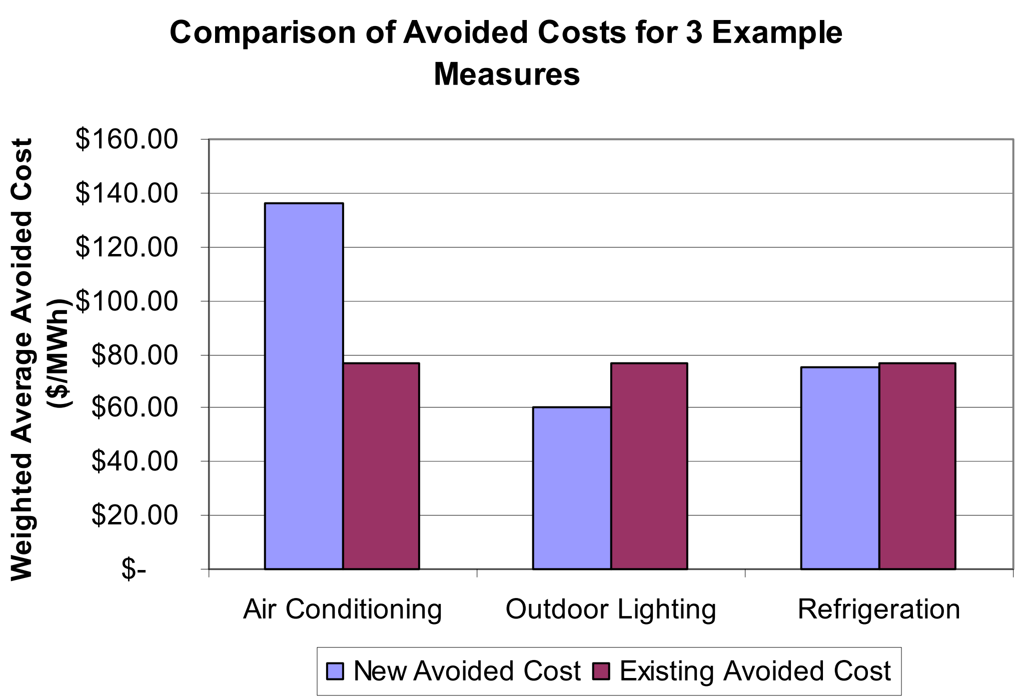

Figure 7: Comparison of new and existing electric results by measure for secondary voltage in PG&E Climate Zone 12

In Figure 8, we show the new gas avoided costs by month and year through the forecast period 2004 to 2023. In the early years of the forecast, the avoided costs vary from $0.52 to $0.73/therm depending on the season and increase to $0.94 to $1.15/therm in 2023. Each year in the forecast has the same basic monthly allocation.

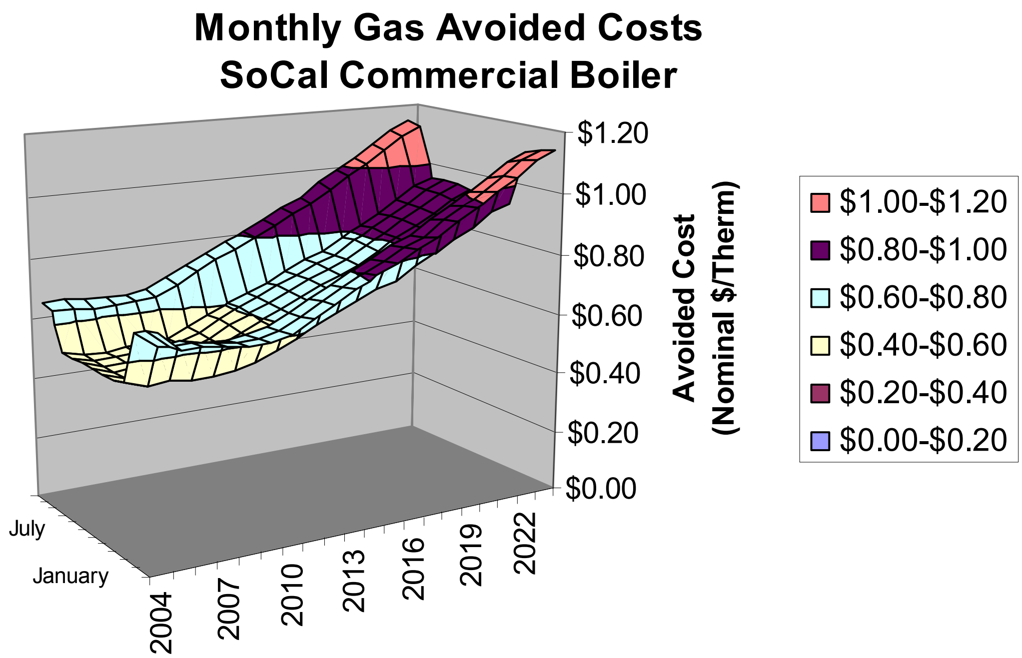

Figure 8: Gas avoided costs by month and year for SoCal Gas commercial customer, large boiler, uncontrolled emissions

Figure 9, we show a comparison of natural gas savings for two measures (heating and boiler efficiency) under the existing and new avoided cost values using a SoCal Gas commercial customer. The vertical axis shows the weighted average savings in $/therm over a 16 year period beginning in 2004. For heating conservation, which is assumed to save energy only during the winter months, the weighted average avoided cost is approximately $0.72/therm with the new avoided costs. This is significantly greater than the $0.51/therm savings this measure would receive with the existing avoided costs. The differential between new and existing avoided cost for boiler improvements is not as large since the measure will save energy all year.

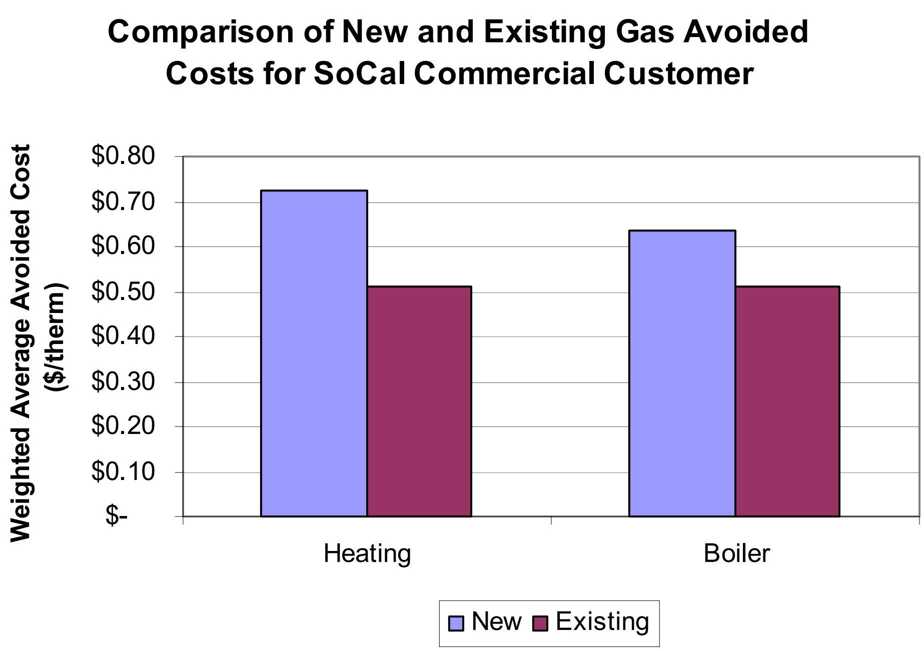

Figure 9: Comparison of new and existing gas results by measure for SoCal commercial customer

2.0 Costing Framework

2.1 Foundations of Avoided Cost Methodology

2.1.1 Existing Standard Practice

The existing values currently used for evaluating Public Goods Charge (PGC) funded programs are specified in the *Policy Manual*.[13] The *Policy Manual* states that "[c]ost-effectiveness is an important measure of value and performance. In order to ensure a level playing field for multiple programs, the Commission will continue to use the standard cost-effectiveness methodologies articulated in the California Standard Practices Manual (SPM): Economic Analysis of Demand-Side Management Programs." (*Policy Manual*, page 15). The SPM identifies a number of cost-effectiveness tests, one of which is the Total Resource Cost Test: Societal Version (TRCSV) that aims to capture the costs and benefits of a program from the perspective of society as a whole.

The existing values have the following components:

- ***Electric avoided cost values***.[14] The generation component is based on an August 2000 CEC forecasts of market prices produced by Multisym, a production (cost) simulation model, with modifications obeying an October 25, 2000 Administrative Law Judge (ALJ) ruling.[15]

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[13] Based on Chapter 4 of the Energy Efficiency Policy Manual Appendix A describes these existing values, their derivation and their input data.
[14] "The avoided costs… are used to quantify the benefits associated with energy demand reduction programs. These avoided costs are based on the cost of the energy, be it a production cost or a market price, that is avoided as a result of energy efficiency programs." (RFP, Page 3).

- [15] Modifications to the CEC forecast were as follows:

  - 2002: CalPX (10/99 to 9/2000)

- ***T&D externality adder***.[16] These are based on Commission adopted values in Resolution E-3592. The current values are the statewide average of avoided T&D costs across utility service territories. They are forecast based on projected utility sales growth and converted from $/kW to $/MWh using assuming a 60% load factor.

- ***Electric and gas environmental externalities***.[17] These are based on Commission adopted values in Resolution E-3592.

- ***Gas Avoided Commodity Costs.*** These are the CEC's August 2000 base-case price forecast.

- 2003-2010: CEC Forecast plus 20%
- 2021-2020: CEC Forecast
- 2021: CEC Forecast escalated by growth rate over previous 5 years

In addition, the generation values incorporate the following on-peak multipliers:

- 2002: 5.0X
- 2003-2005: 2.0X
- 2006-2021: 3.0X

[16] "The second externality adder currently used in the TRCSV is for Transmission and Distribution (T&D) effects. The T&D externality adder captures the line losses that occur in the transmission and distribution of electricity, as well as the increased cost of maintenance and upgrades to the transmission and distribution system associated with increased energy use. The avoidance or delay of these system maintenance and upgrade costs, through demand reduction programs, is included in the TRCSV as a benefit resulting from these programs." (RFP, Page 4)

[17] "The externalities… are considered added costs associated with the production of energy, or conversely the added benefits associated with the reduction in energy production. These costs are considered externalities because they are costs that are not factored into the market prices or production costs by market agents, and hence are "external" to the market. The TRCSV provides for the inclusion of the externality adders as a benefit resulting from energy demand reduction programs. The TRCSV adds the quantified value of these externalities to the avoided cost of energy to fully capture the benefit of demand reduction programs.

Of the four externality adders that are the subject of this RFP, two have been developed and used in recent years by the CPUC in their TRCSV cost effectiveness calculations. Under the current CPUC structure for cost-effectiveness analysis the two externality adders, used in the TRCSV, are an environmental adder and a transmission & distribution adder. The environmental externality adder attempts to quantify, on a per/kWh and per/therm basis, the negative impact on the environment, or cost to society resulting from the generation of electricity and the direct combustion of natural gas. This externality, in its most recent valuation, was quantified by analyzing the value of pollution permits traded in California." (RFP, Page 3-4)

- ***Gas T&D.*** These are calculated from the weighted average of gas T&D costs in PG&E, SDG&E and SoCal Gas territories used in utility 2000 annual reports.

2.1.2 The Time Dependent Valuation (TDV) Methodology

As a result of the collaborative process described in the executive summary of this report, E3's recommended method is time dependent valuation (TDV), a concept employed by E3 during a project sponsored by the CEC.[18] The TDV concept is that energy efficiency measure savings should be valued differently at different times and locations to better reflect the true avoidable costs to users, to the utility system, and to society. Therefore, our recommended scope of deliverables includes several important time- and location-specific dimensions.

Using electricity as an example, the TDV concept suggests that the value of energy and capacity savings during hot summer weekday afternoons should be greater than at other times because California has high demand on summer afternoons that cause high electricity prices and trigger T&D capacity investments.

Our recommended method develops each hour's electricity valuation using a bottom-up approach to quantify an hourly avoided cost as the sum of elements of forward-looking incremental costs for that hour. The resulting hourly electricity avoided costs are location-specific and vary by hour of day, day of week, and time of year. The location and time variations by cost component are as follows:

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[18] The Time-Dependent Valuation (TDV) initiative has been the top priority of 28 proposed changes for the CEC in its 2005 Standards Update. See http://www.energy.ca.gov/2005_standards/selected_measures.html for the ranked

10. Generation Costs – variable by hour and location. The annual forecast of generation costs avoided is allocated according to an hourly price shape obtained from historic data that reflect a workably competitive market environment. These hourly costs further vary by location, depending on locational capacity constraints and fuel costs.

11. T&D Costs (transmission and distribution) – variable by hour and location. The T&D capacity costs are allocated by typical weather patterns for the State's climate zones, with the highest costs allocated to the hottest temperature hours, as done in the CEC TDV evaluation. Non-peak hours have zero avoided T&D capacity costs, reflecting that T&D capacity investments are made to serve peak hours.

12. Emissions Costs – variable by hour. Generation market prices capture the per-MWH variable costs of buying emission permits required to comply with emissions regulations incurred by generators. However, emissions such as CO_2 are unpriced, thus constituting external costs. Under TDV, we allocate such external costs based on the time profile of generation dispatch with on-peak hours having higher emission costs than off-peak hours.

13. Reliability Adder – variable by hour. This adder reflects the reliability benefit of a demand reduction not already captured in the avoided cost of generation. To illustrate, the market price of firm energy already contains the market value of capacity, but does not include the price (or marginal cost) of ancillary services required by California Independent System Operator (CAISO) for safe and reliable operation of the grid.

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list. The CEC intends to adopt different hourly avoided costs for the 16 climate zones within California in its 2005

14. Price Elasticity Adder – variable by hour. This adder is related to the benefit of a price reduction to all electricity consumers caused by a demand reduction. This benefit, however, is likely to be relatively small in the next few years because of the utility distribution company's (UDC) reduced reliance on the spot markets for meeting their load obligations. When the electric system is in resource-load balance, the benefit vanishes because a demand reduction along the flat long-run supply curve (which reflects the cost of market entry, the all-in per MWH cost of a CCGT) does not result in a price decrease.

Figure 10 illustrates the additive components of electricity avoided costs over a Monday to Friday summer work-week. The top outline of the curve represents the total avoided cost for each hour, while the different colored regions indicate each component's contribution to the total costs in that hour. Except for generation avoided costs, the remaining cost components are labeled as "externalities", as referred to in the RFP for this analysis. Starting with the generation avoided cost, we first add the cost of environmental externality (unpriced emission cost), then T&D externality (capacity costs), reliability externality (AS costs), and finally, the price elasticity externality (multiplier effect). In the example shown in Figure 10, the T&D externality equals zero for all days except for Wednesday, which is assumed to be very hot. Therefore, a portion of the T&D costs are allocated to Wednesday's energy value.

Energy Efficiency Standards Update (expected adoption date of December 1, 2003).

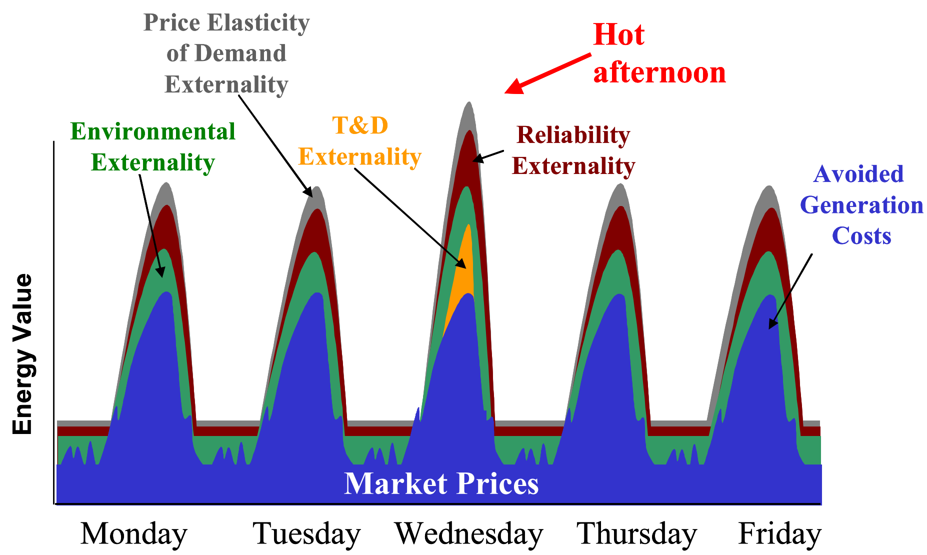

Figure 10: Time Dependent Valuation (TDV): An illustrative example of how costs are allocated to time

The avoided cost of natural gas has similar additive elements of forward-looking incremental costs. Since natural gas can be stored and its prices vary mainly by season, its location-specific avoided cost estimates vary by month, rather than by hour.

2.1.3 Stress Case Scenarios

Even the best, unbiased forecast of hourly avoidable electricity and gas costs for the years 2004 through 2023 will only be a point estimate among a wide range of plausible alternative scenarios. The forecast uncertainty is caused by the uncertainty of the fundamental cost drivers related to owning and operating new generation plants. These cost drivers include:

- The future costs of natural gas that are positively correlated with fluctuating hydro production;[19]
- The efficiency of converting fuel to electricity;
- The costs of owning new plants;
- The operations and maintenance (O&M) costs (besides fuel) of operating new plants;
- Changes in the future costs of meeting emissions standards;
- Demand growth in the California control area; and
- The continually evolving market structure of the control areas embedded in the Western Interconnection.

Given these sources of uncertainty in the cost drivers, we recommended that the scope of the deliverable be expanded to include avoided costs and adders by several important stress case scenarios. For example, it might be more appropriate to evaluate load control programs with avoided costs that are developed for cases where there is a physical shortage due to high growth or low hydro conditions and very high gas prices.

[19] A wet hydro year reduces the demand for natural gas used in thermal generation, thus depressing spot natural gas prices.

2.1.4 Spreadsheet-Based Model

To provide a sound, transparent and repeatable methodology to the major stakeholders, we also recommended that the deliverables should include a spreadsheet based model, along with all the supporting data. This would permit the CPUC staff and interested third parties to change input assumptions and create alternative estimates of avoided costs. [20]

2.2 Total Avoided Cost Formula for Electric and Gas

In this section, we describe the formulation used to compute the total avoided cost estimates for electricity and gas for the forecast horizon of 2004-2023. First we define the term "total avoided cost" and its appropriate use. Then we describe the electricity avoided cost formulation, followed by the natural gas avoided cost formulation.

2.2.1 Total Avoided Cost Definition

This formulation of avoided cost is designed to update the current avoided costs described in the *Policy Manual*. E3 designed the avoided costs provided in this report to be used within the existing cost-effectiveness evaluation framework as defined by the Standard Practice Manual (SPM).[21] We have developed our avoided cost value streams to include the same basic components of value that efficiency provides.

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[20] Although in the past we have worked extensively with production simulation models to forecast avoided energy costs, we do not believe that the alleged precision of simulation models would increase the accuracy or usefulness of the avoided cost forecasts. A case in point is that input data uncertainty (e.g., fuel price and demand growth), if not carefully addressed, can easily overwhelm any alleged precision obtainable from computer simulation.
[21] California Public Utilities Commission, *California Standard Practice Manual: Economic Analysis of Demand Side Programs and Projects*, October 2001

However, E3 has recommended some changes to the methodology for determining avoided cost values. These methodological changes include (1) incorporating the market price effects, (2) including the value of reliability through ancillary services, and (3) the disaggregation of the avoided costs to time (hour, month, or time-of-use (TOU) period) and to California climate zones.

The term "total avoided cost" refers to the total cost avoided to society through reduction in energy demand, which can be either electricity or gas. E3 computes these avoided costs from a societal perspective thus capturing the overall benefits to all energy consumers including both direct savings and externality values of unpriced emission (e.g., CO_2).

The resulting avoided costs are appropriate for applying the "Total Resource Cost (TRC) test – Societal Version" which is the primary cost-effectiveness test for California efficiency programs.[22] This test, as defined in the SPM, is intended to measure the overall cost-effectiveness of energy efficiency programs from a societal perspective, taking into account benefits and costs from a wider perspective as opposed to one individual or stakeholder.

2.2.2 Electricity Avoided Cost Formulation

We show the basic formulation of the total electric avoided costs in Figure 11. In the formulation of total avoided cost, we use the same three basic components that are included in

[22] California Public Utilities Commission, *Energy Efficiency Policy Manual: Version 2*, August 2003, Page 15, San Francisco, CA

the current avoided costs described in the *Policy Manual*.[23] These are the (1) avoided generation costs, (2) avoided transmission and distribution costs, and (3) environmental externalities. The total avoided cost is computed as the sum of three main components for each utility, climate zone, voltage level, hour, and year.

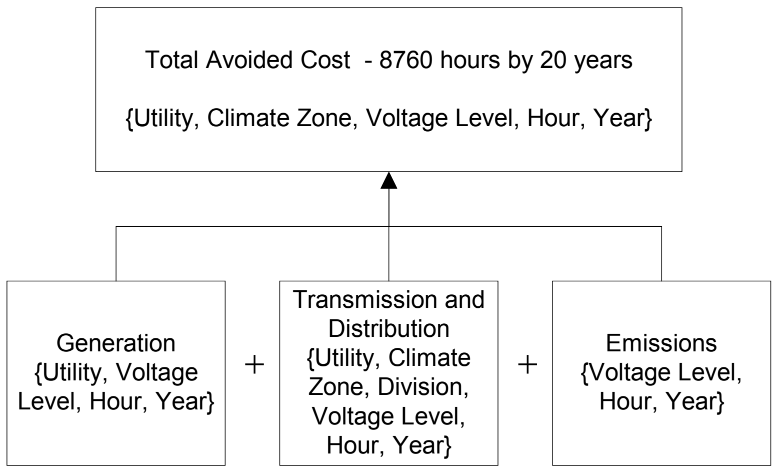

Figure 11: Formulation of Total Electric Avoided Cost

The individual formulae our team used to calculate the avoided cost components provided in this report are described in this section. Subsequent sections of this report describe each of the inputs to these components in greater detail.

Formulation of Generation Avoided Cost

In Figure 12, we show the avoided generation cost formula. We calculate this as the product of the hourly market price for firm energy in each year, one plus ancillary services percentage, one plus energy losses percentage, and the market multiplier. We compute the market price as the

[23] California Public Utilities Commission, *Energy Efficiency Policy Manual: Version 2,* August 2003, Page 21, San

product of an hourly market price shape and an average market price. We compute the market multiplier as the residual net short position (RNS) (unhedged position) and the market elasticity estimate of price response for changes in demand level. Finally, we develop the average market price forecast over three distinct periods; (1) a period of forward market liquidity, (2) a transition period to resource balance, and (3) a post-resource balance year long run marginal cost (LRMC) forecast.

Francisco, CA.

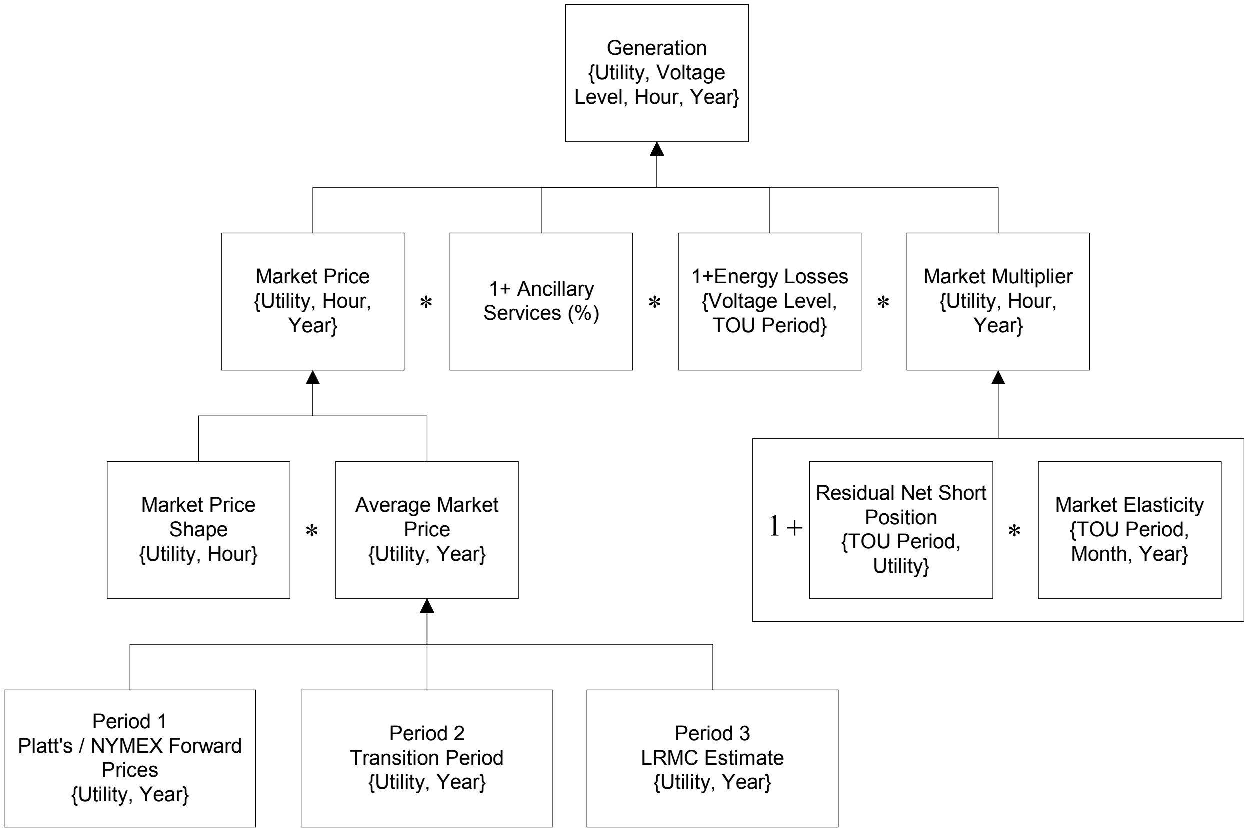

Figure 12: Generation Avoided Cost Formula

We briefly describe the four cost inputs to the generation component in this section, with additional detail provided in subsequent sections of this report.

(1) Market price of generation is an hourly market price over the 20-year forecast horizon. This is calculated using an hourly market price shape based on historic PX data and a forecast of average annual market prices.

(2) Ancillary services (AS) costs are the costs incurred by the CAISO to reliably operate the California grid. We express the avoided AS cost as a percent of the hourly market price for convenience.

(3) Energy losses are the losses from the point of delivery at the customer who has implemented the efficiency measure to the hub on the bulk power system.[24] The loss factors represent the average marginal losses for each TOU period and vary by voltage level.

(4) Market multiplier is a factor that magnifies the generation avoided cost because a demand reduction via demand side management (DSM) or energy efficiency (EE) programs can reduce market clearing prices (MCP), thus benefiting all electricity users, not just the program participants. When a UDC has retained generation and forward power contracts signed by the California Department of Water Resources (CDWR) and allocated by the Commission, the multiplier is (1 plus Residual Net Short (RNS) as percent of the UDC's demand times market clearing price (MCP) elasticity with respect to load), see Section 2.7.

(5) Market price shape is an hourly market price calculated for each utility based on historically observed market prices at NP15 (PG&E) and SP15 (SCE and SDG&E). The same overall price shape is assumed in every year of the forecast.

(6) The average market price is our base case forecast for the 20-year forecast horizon. The forecast of market price uses a hybrid approach that uses publicly available market price data and cost data in three distinct periods:

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[24] A hub is a location in the wholesale power market where price quotes are available (NP 15, SP 15).

Period 1 (Market): Years before load-resource balance and with electricity forward trading. This period has observable forward prices that forecast the sum of (a) generation (private) marginal cost and (b) emission compliance cost paid by a generator.

Period 2 (Transition): This period contains the transition years between the end of Period 1 to the beginning of Period 3. Period 2 is calculated as a linear trend between the market price in the last year of Period 1 and the first year of Period 3.

Period 3 (Resource Balance): This period occurs after the California system is assumed to be in resource balance. The assumption of load-resource balance implies system supply matching demand in these years. Relatively easy entry and exit in a workably competitive market environment implies a flat supply curve defined by the LRMC, the all-in per MWh cost of new generation to meet an incremental demand profile. The market multiplier (1+ RNS percent * Market Elasticity) is equal to 1.0 in Period 3 because the market elasticity is 0.0 when the supply curve is flat at the LRMC and small demand changes do not alter the LRMC price.

Formulation of T&D Avoided Cost

In Figure 13 we show the formula we used to calculate the T&D avoided cost. The estimate of electric T&D avoided cost is decomposed by utility, climate zone, division, voltage level, hour, and year. We calculated the avoided cost as the product of an estimate of T&D capacity by utility division and year, hourly allocation factors for each climate zone, and one plus the peak losses on the system.

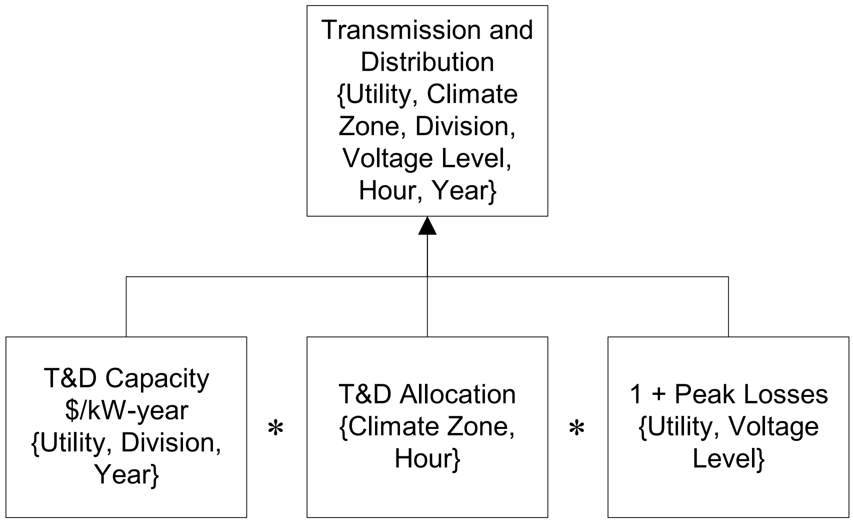

Figure 13: Formulation of T&D Avoided Cost

We briefly describe the cost inputs for the T&D avoided cost components and provide additional detail in subsequent sections.

(1) T&D capacity value is an estimate of the forward looking avoidable delivery costs. Each utility estimated these costs using either the present worth (PW) method, or the discounted total investment method (DTIM).

(2) T&D allocation factors are percentages of the total T&D capacity cost for each hour of the year. These percentages, or weighted allocation factors are based on typical meteorological year (TMY) weather data for each climate zone.

(3) Peak losses are an estimate of the incremental losses during the peak hour of the year between the end-use customer and the distribution system and transmission system. The losses vary by voltage level.

Formulation of Environmental Avoided Cost

In Figure 14 we show the formula used to calculate the avoided environmental cost, or emissions costs. The emissions costs vary by voltage level, hour, and year. We computed them as the sum of NOx, PM10, and CO_2 costs increased by marginal energy losses for each TOU period. We estimated the emissions avoided cost streams by multiplying the costs per pollutant (on a yearly basis) by the emission rate (per hour of the year).

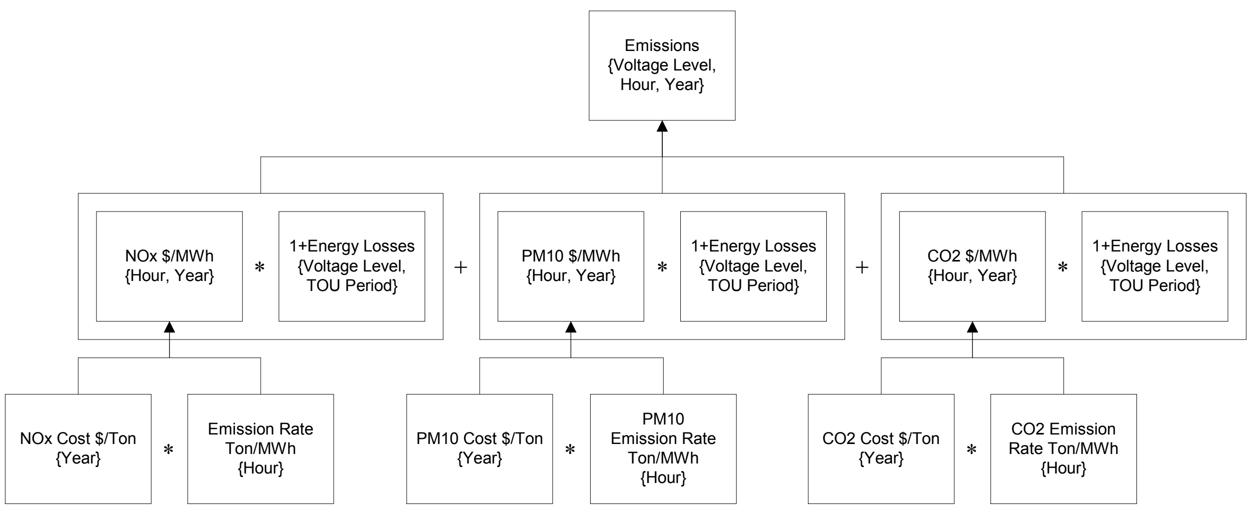

Figure 14: Formulation of Emissions Avoided Cost

We briefly describe the cost inputs here and provide additional detail in Section 2.4.

(1) The NOx costs ($/MWh) are the estimate of avoided costs for reduction in electricity generation. These are based on California offset prices generators must pay for NOx emissions, and the estimated emission rate of NOx at the implied heat rate of the market price. The NOx cost per MWh of energy saved at the customer is increased by the incremental energy losses in each TOU period between the end use and the bulk system. In Period 1 when the forward market prices of electricity are based on NYMEX forward market prices, we assume that these prices already include the cost of NOx emissions so this value is equal to zero in Period 1.

(2) The PM10 costs ($/MWh) are the estimate of avoided costs for reduction in electricity generation. These are computed similarly to the NOx costs, with the emission cost based on the California PM10 market prices and the estimated rates of emissions by implied heat rate. The PM10 costs are also assumed to be included in the NYMEX forward market prices.

(3) The CO_2 costs ($/MWh) are an estimate of avoided costs for reduction in CO_2 per MWh saved at the customer site. There is not currently a requirement to purchase CO_2 offsets in California so the avoided cost of the CO_2 emissions is based on prices in other markets. The estimates we produce are used as a long-run average added in all years of the forecast horizon.

2.2.3 Aggregated Formula for Each Forecasting Period

In summary, Equation 1 is used to estimate the electricity avoided costs. We removed the dimensions of each of the inputs for clarity. Notes are provided below Equation 1 to explain specifics in each forecast periods.

Equation 1: Total Electricity Avoided Cost

Electricity Avoided Cost = Price Shape × Market Price × (1+AS) × (1+RNS*elasticity) × (1+ Losses) + Emissions × (1+ Losses) + T&D Cost × T&D Allocation × (1+Pk Losses)

Notes by Period for Equation 1

Period 1 (Market)

- Market Price is based first on forward electricity data, then on forward gas prices
- Emissions costs are based only on CO_2. The NOx and PM10 prices are assumed to be included in the market price in the market period.

Period 2 (Transition)

- Market Price is a linear transition between Period 1 and Period 3 prices.

Period 3 (LRMC)

- Market Price is based on LRMC of combined cycle gas plant and long-run forecast of gas prices.
- RNS is assumed to be zero after system is in resource balance.

2.2.4 Total Gas Avoided Cost

We compute the total avoided gas costs using a methodology that parallels the total electric avoided cost approach. The total gas avoided costs are shown in Figure 15, as the sum of the forecasted commodity price for natural gas, the avoided transmission and distribution costs, and the emissions costs. The total avoided gas costs are calculated for each utility, service class, combustion type (emission control technology), month, and year.

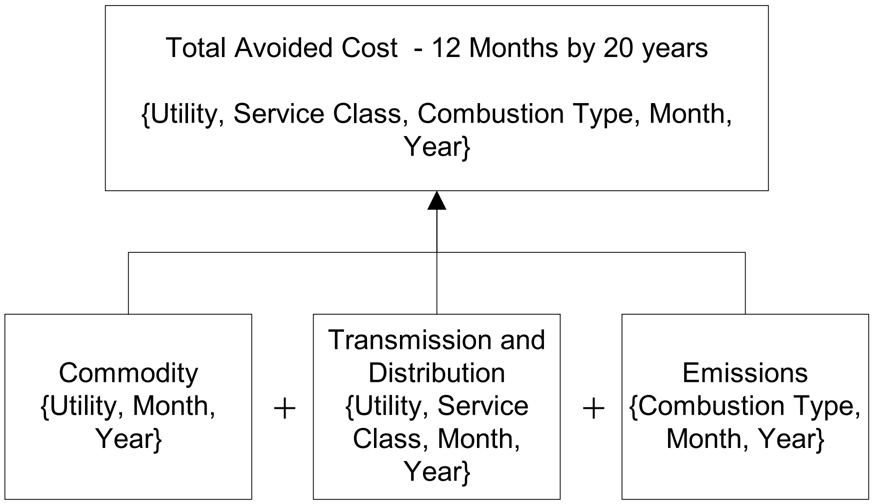

Figure 15: Formulation for Total Gas Avoided Cost

Formulation of the Avoided Commodity Cost

In Figure 16, we show the calculation of the avoided commodity for each utility, month, and year. The avoided commodity is calculated as the product of the forecasted market price and one plus the avoided compression gas and reduced loss and unaccounted for gas percentages. Similar to the avoided electricity calculation, the gas commodity is forecasted for three periods. Period 1 is the period when forward market prices for gas are available from NYMEX, Period 2 is a transition, and Period 3 is based on a long-run forecast of future prices. In addition to the gas avoided cost, the gas commodity costs are used in conjunction with the UDC's gas transportation tariff for generation to estimate the long-run avoided electricity generation costs.

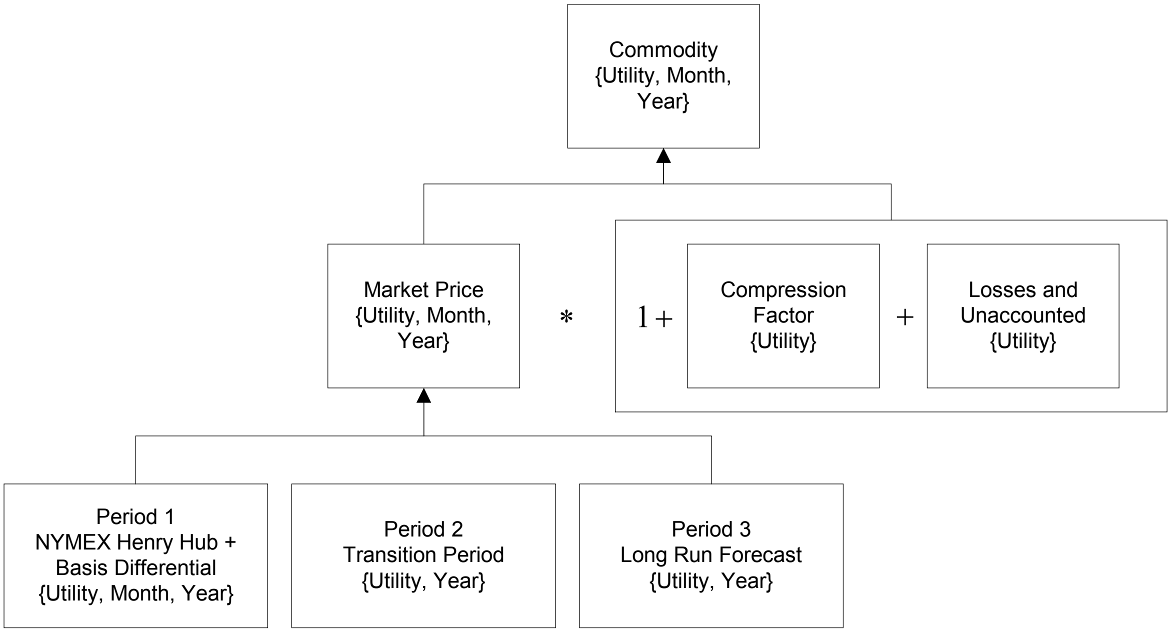

Figure 16: Formulation of Avoided Commodity Cost

We briefly describe the cost inputs here and provide additional greater detail in subsequent sections.

(1) Market price is the commodity cost at PG&E Citygate or SoCal territory. The commodity cost forecast is calculated for three different periods in the same way as is done for avoided costs of electricity.

Period 1 (Market): For the period when market data is available based on NYMEX futures trading, the market price of gas is based on the market data. The Henry Hub market is used because it is the most liquid market in the country and correlates with the PG&E and SoCal gas prices. The Henry Hub prices are adjusted to the city-gate prices by adding (or subtracting) a basis differential calculated using historical data.

Period 2 (Transition): The transition period is included to ensure a smooth transition from the NYMEX market during Period 1 to the long-run forecast of gas prices in Period 3. The transition period is currently 36 months.

Period 3 (Long-run Forecast): A long-run forecast of annual average commodity prices are used after the period of market liquidity and transition. These prices are based on the CEC forecast of gas commodity prices and the monthly shape expressed in the last year of the NYMEX market data.

(2) Compressor fuel cost incurred by a gas UDC to operate its gas grid and expressed as a percent of the market price.

(3) Lost and unaccounted for (LUAF) gas are the losses in the system and expressed as a percentage of market price.

Note that we do not include a gas market multiplier in the calculation of commodity prices because a small change in the in-state gas demand does not alter the gas price forecast, as seen in Section 2.8.

Formulation of Avoided T&D Cost

The avoided gas T&D costs represent an estimate of marginal transportation cost for delivering gas to end-users. Note that this is not the same as the embedded cost of gas delivery the UDC charges non-core customers. Rather, we calculate the avoided T&D cost as the product of the T&D marginal cost for each utility, service class, and year by the monthly T&D allocation.

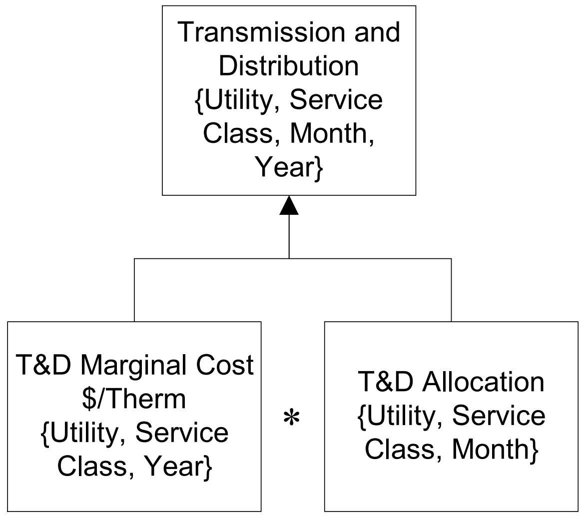

Figure 17: Formulation of Avoided T&D Cost

We briefly describe the cost inputs here and provide additional detail in subsequent sections.

(1) The T&D marginal cost is the average T&D cost per therm of delivering gas to each service class. The marginal gas transmission cost is not based on peak throughput, but rather the average delivery cost per therm based on the usage profile for each class.

(2) The T&D allocation assigns the natural gas capacity cost to the winter season based on the volumetric throughput on each utility system. We do not assign any T&D capacity costs to the summer months when volumes on the gas system are low. The formulae for the T&D allocation is as follows:

Winter Season Factor (%) = 1 + (summer volume / winter volume)

Summer Season Factor = 0%

This effectively allocates all of the T&D costs to the 5 winter months of November through March.

Formulation for Avoided Emissions Cost

In Figure 18 we show the formulation of the avoided emissions costs for reduced natural gas consumption. The avoided emissions are computed as the sum of the reduced NOx and CO_2 costs based on the same offset market prices used in the calculation of the avoided electricity prices. Since PM10 emissions are negligible for natural gas end-use combustion, they do not represent a significant pollutant and are therefore not included in this estimate of avoided costs for gas.

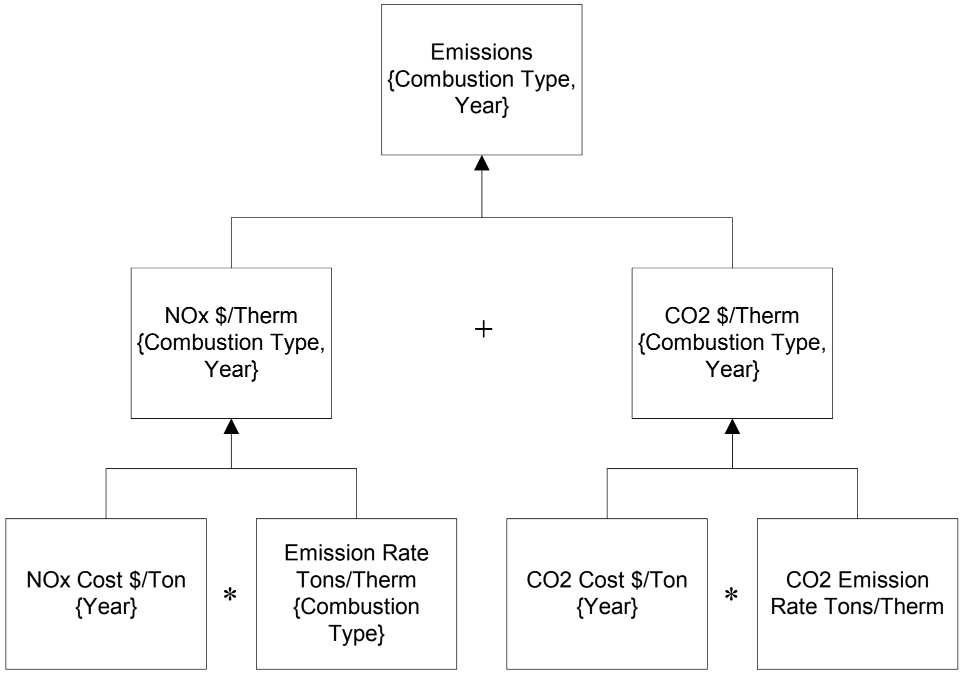

Figure 18: Formulation of Avoided Emissions Cost

The cost components are described briefly here, and in greater detail in subsequent sections.

(1) NOx ($/Therm) is the avoided cost of reduced NOx emissions per therm saved. This is computed as the product of the market price for NOx offsets by year, and the average emission rate of NOx per therm for each combustion type. For residential furnaces we assume that all combustion is uncontrolled. For boilers we use emissions rates for three combustion types; uncontrolled, flue gas recirculation, and low NOx burner.

(2) CO_2 ($/Therm) is the avoided cost of reduced CO_2 emissions per therm saved. The value of CO_2 emissions reduction uses the same market prices for CO_2 times the emissions rate of combusted CO_2. We assume there is no difference in CO_2 emission by combustion type.

Note that unlike the electricity avoided costs where emissions savings occur at the generator and are therefore increased by losses, gas emission reductions occur at the end use and are not adjusted by the factor that accounts for the compressor fuel or LUAF.

2.2.5 Aggregated Formula for Each Gas Forecasting Period

In summary, we used Equation 2 is used to estimate the gas avoided costs. Again, we have removed the dimensions of each of the cost inputs for clarity. Notes are provided below Equation 2 to explain specifics in each forecast periods.

Equation 2: Total Gas Avoided Cost

Avoided Cost = Commodity Price × (1 + Compression + LUAF) +

T&D Cost × T&D Allocation + Emissions

<u>Notes by Period for Equation 2</u>

Period 1 (Market)

- Market Price based on forward gas data

Period 2 (Transition)

- Market Price is a linear transition between Period 1 and Period 3 prices

Period 3 (LRMC)

- Market Price is based on long-run forecast prepared by the CEC

In the following sections, we describe in detail the methodology we used to calculate each of the components that employed to determine the total electric and gas avoided costs. Each remaining sub-section in Section 2.0 (Costing Framework) represents a separate avoided cost component.

2.3 Generation Avoided Cost

In this section we describe the methodology and present the results of the "hourly stream[s] of values for the avoided cost of electricity generation or day-ahead market price, in dollars/[M]Wh… associated with the years 2004-2023" (RFP, page 5). In addition to the CPUC's requested hourly variation in electricity generation values, we also provide values that vary by location. We estimate the twenty-year streams of hourly avoided costs of electricity generation by utility (PG&E, SDG&E, and SCE) and voltage level (transmission, primary, and secondary).

In Figure 19, we show the formulation of the avoided cost of electricity generation. In each box we specify the dimensions of the calculated numbers. For example, the annual market price forecasts (Box 3b) vary by utility and year, and the final generation avoided costs (Box 1) vary by utility, voltage level, hour and year.

We developed the annual market price forecasts (Box 3b) for three distinct periods; a period of forward market liquidity (Box 4a), a post-resource balance year long-run marginal cost (LRMC) forecast (Box 4c), and a transition period between them (Box 4b). We allocate these utility-specific annual market price forecasts using an hourly market price shape (Box 3a), thus introducing an hourly dimension. Finally the hourly costs (Box 2a) are adjusted to account for energy losses (Box 2b), which introduces the voltage level dimension.

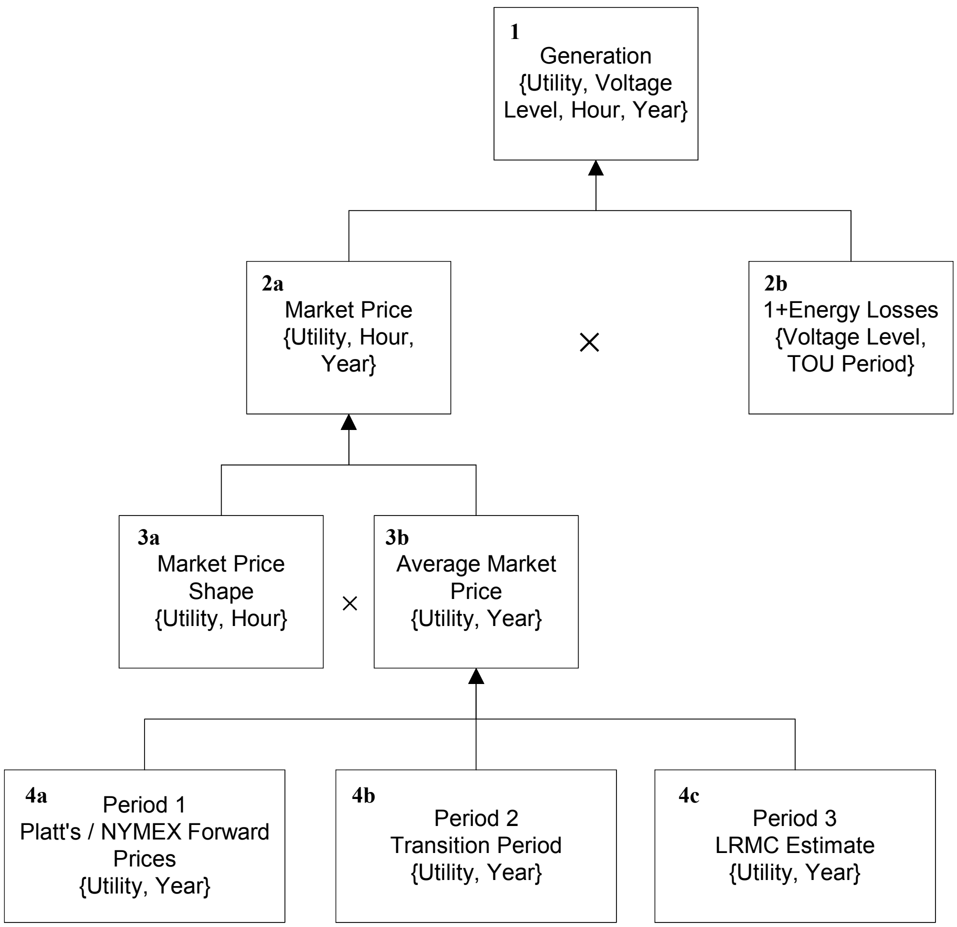

Figure 19: Formulation of the generation avoided cost component.

2.3.1 Key Findings

Our key findings from this section are:

1. The most appropriate source of data for estimating the avoided costs of electricity generation is forward market prices. The electricity forward prices are for firm long-term power and reflect the market's expectation of future spot prices plus the hedge value.[25] We use forward market price quotes for calendar years 2004, 2005 and 2006 from Platts' *Megawatt Daily* as of October 15th, 2003, as shown in Table 2. The forward electricity market prices are for the (6x16) on-peak hours (06:00-22:00 Hrs, Mon-Sat) and delivery to NP15 and SP15. We estimate the off-peak prices for hours outside the on-peak period as a percentage of the on-peak market prices. This percentage is based on the historic on- to off-peak spot price ratio found in the market clearing prices produced by the California Power Exchange (PX), prior to the Energy Crisis.[26]

Table 2: Long-term forward market prices ($/MWh) for on-peak delivery to NP15 and SP15

Hub	Nov	Dec	Q1 04	Q2 04	Q3 04	Q4 04	Cal2004	Cal2005	Cal2006
NP15	51.25	54.75	53.00	47.25	60.50	52.50	53.30	52.75	52.75
SP15	52.50	55.50	54.25	50.75	62.00	52.75	54.95	56.25	56.25

Source: Platts' *Megawatt Daily* for Oct 15, 2003. We use the Cal2004, Cal2005 and Cal2006 prices for the forecast.

2. The Platts' forward electricity prices are only available through 2006. However, NYMEX natural gas futures are traded for 72 consecutive future months, or two years beyond the end

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[25] For a discussion on the computation of hedge value in the form of a risk premium, see Woo, C.K., I. Horowitz and K. Hoang (2001) "Cross Hedging and Forward-Contract Pricing of Electricity," *Energy Economics*, 23: 1-15; and Woo, C.K., I. Horowitz and K. Hoang (2001) "Cross Hedging and Value at Risk: Wholesale Electricity Forward Contracts," *Advances in Investment Analysis and Portfolio Management*, 8, 283-301.

[26] The same approach is used by Woo, C.K., I. Horowitz and K. Hoang (2001) "Cross Hedging and Forward-Contract Pricing of Electricity," *Energy Economics*, 23: 1-15.

of the electricity forward price data. We extend the electricity price forecast to 2007 using the changes in the natural gas future prices and assuming that the spark spread is constant over the period between 2006 and 2007.

3. Under the assumption of load-resource balance with easy entry, an electricity supply curve at long-run market equilibrium is flat and defined by the long-run marginal cost (LRMC) of a combined cycle gas turbine (CCGT).[27] For the base case we have set 2008 as the resource balance year for all three utilities.

4. For the period from 2008 through the end of 2023, we assume that the cost of electricity will be equal to the full cost of owning and operating a combined cycle gas fired generator. This assumption is based on an estimated need for new capacity in the California Control area in 2008 (the resource balance year) and extensive evidence from the CEC, the Western Electricity Coordinating Council (WECC), and the Energy Information Association (EIA) that the majority of new resources being added in the Western Interconnect are gas fired combined cycle generators (CCGT). We use plant cost and performance data for a combined cycle baseload plant from a CEC August 2003 staff report[28] to forecast the long-run generation costs. Gas prices are the forecasted prices to generators in the utility's service area, as described in Section 2.8 of this report

5. Since resource balance occurs before the NYMEX gas futures data ends, there is no need to create a "transition period." However, the general costing framework is developed to allow

[27] For a characterization of a long-run market equilibrium, see Katz, M.L. and H.S. Rosen (1991), *Microeconomics*, Irwin, MA: Boston, pp.385-387.
[28] "Comparative Cost of California Central Station Electricity Generation Technologies" CEC Staff Final Report Aug 2003, Appendix D and Assumptions for Equity Return and Debt Interest Rates, Table 2.

for a transition period. For example, if in future updates it were determined that the resource balance year would occur after 2008, we use simple linear trending to yield the annual avoided generation costs between the last year supported by market price data and the first year in which long term benchmark costs are used.

6. Steps 1 through 5 yield the annual forward prices by utility as shown in Figure 20. The small variation by utility is a result of (1) differences in the forward market prices at NP15 and SP15, and (2) differences in the delivered cost of natural gas to generators at PG&E, SDG&E, and SCE.

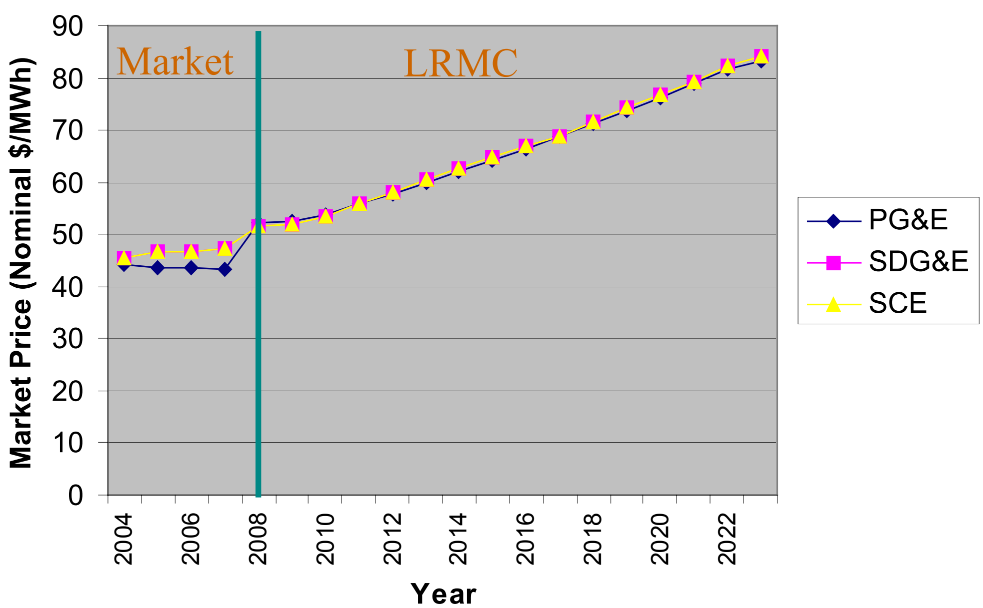

Figure 20: Annual average price forecasts by utility for 2004 through 2023 as of October 15, 2003.

Prices to the left of the resource balance year in 2008 are derived from energy forward and future markets, and prices after 2008 are based on the LRMC of a CCGT

7. We allocate the annual generation prices to hours of the year using an hourly shape derived from the California PX hourly NP15 and SP15 zonal prices from April 1998 - April 2000, the period immediately prior to the Energy Crisis. We apply the NP15 hourly price shape to the PG&E annual forecast and the SP15 shape to the SDG&E and SCE annual forecasts.

8. Finally we apply each utility's average energy losses by TOU period as a multiplier to the hourly avoided generation costs. Losses differ by transmission, primary and secondary voltage levels.

9. Since there are three utilities and three voltage levels, Steps 1 through 8 yield nine sets of twenty-year generation avoided hourly cost forecasts. Figure 21 illustrates the average avoided cost results by month and hour of the day for PG&E at the secondary voltage level.

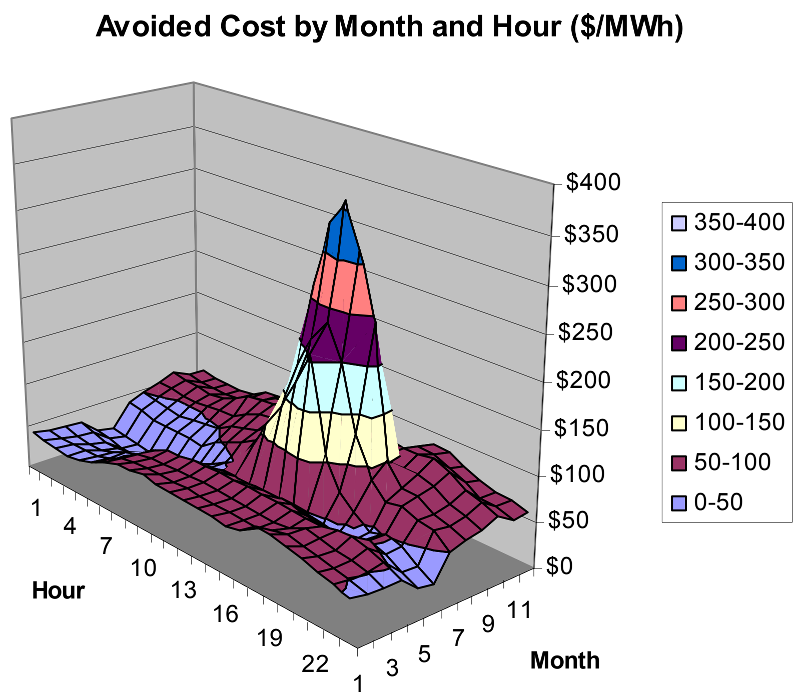

Figure 21: Average avoided costs by month and year for PG&E, secondary voltage level. The costs shown are the levelized values over the 20-year forecast, assuming a program start date of 2004.

2.3.2 Background

Avoided energy costs "…are used to quantify the benefits associated with energy demand reduction programs. These avoided costs are based on the cost of the energy, be it a production cost or a market price, that is avoided as a result of energy efficiency programs." (RFP, page 3). As recognized in the CPUC's October 2001 Standard Practice Manual (SPM): Economic Analysis of Demand Side Management Programs,[29] "[w]ith a deregulated market for wholesale electricity, marginal costs for electric generation energy should be based on forecast market prices, which are derived from recent transactions in California energy markets" (SPM, page 27).

The CPUC's existing generation avoided costs are based on modified CEC August 2000 forecasts of market prices produced by Multisym, a production (cost) simulation model. Three distinct disadvantages of a complicated production simulation model, such as Multisym, are: (1) it uses numerous non-transparent assumptions; (2) updates to the model to account for frequently changing market conditions are time consuming; and (3) the software is proprietary and difficult to use, thus making it costly to use by parties who are either untrained and do not subscribe to the software. Our recommended approach is to develop a long-term forecast that relies on transparent publicly available market price indices for the period between 2004 and 2008 when such data are available, and the costs of adding new resources over the remainder of the forecasting period. This approach allows for rapid updating of the avoided cost estimates that can be readily verified by all stakeholders (e.g., utilities, staff of CPUC and CEC, and such

[29] http://www.cpuc.ca.gov/static/industry/electric/energy+efficiency/rulemaking/resource5.doc

intervenors as Natural Resources Defense Council (NRDC) and The Utility Reform Network (TURN)), whenever changes in market conditions are observed.

Long-Term Contracts Signed by the California Department of Water Resources

The costs of the California Department of Water Resources (DWR) contracts do not affect our estimates of avoided generation costs. The DWR contracts are now utility resources that are only dispatched when their variable costs per MWH are less than the market price. Absent a market shortage, the last dispatched unit's per MWH variable cost sets the competitive market price. If a market shortage occurs, the market price may exceed the last dispatched unit's cost per MWH because it contains the markup (or capacity value) necessary to clear the market by equating market demand and supply. Therefore, the market price always measures the avoided cost of generation.

To see this point in the current context, consider the Commission's September 23, 2002 Decision 02-09-053 that allocated portions of the DWR long-term contracts to PG&E, SDG&E and SCE. Many of these are tolling agreements whose variable fuel costs are directly passed to the utilities. To meet its obligation to serve retail loads, the utility economically dispatches its allocated DWR contracts and its retained generation. Given its marginal fuel cost, the utility makes its dispatch decision based on the prices in various markets, including bilateral markets for spot and forward energy in California and surrounding states, and the CAISO's AS market.

The following two examples illustrate a utility's economic dispatch:

- The first example is characterized by an energy surplus caused by a wet hydro year. The surplus causes the spot energy price for firm delivery to be so low that it is below the utility's marginal fuel cost. To reduce its fuel cost, the utility buys spot energy to displace output and fuel costs from its share of the DWR contracts and retained generation. Hence, the utility's marginal generation cost is simply the spot market price.
- The second example is characterized by an energy shortage in a dry hydro year. The shortage causes the spot energy price to be so high that it far exceeds the utility's marginal fuel cost. In response to the high price, the utility generates in excess of its own retail sales requirements and sells the excess in open markets. The opportunity cost of not producing one kWh is the spot price, not the utility's own marginal fuel cost. Should the utility decide to reduce the sale by one kWh, it would give up the revenue from that kWh, which is equal to the spot energy price. Hence, the utility's marginal generation cost is the spot energy price.

In both examples, the utility's marginal generation cost is the market price.

Electricity Forwards

We use electricity forward prices that are collected and reported by Platts' *Megawatt Daily*. The two points of delivery are North of Path 15 (NP15), where the majority of PG&E's load is located, and South of Path 15 (SP15), where SDG&E and SCE's loads are located. Each forward price quote for a specific delivery point applies to the standard wholesale market definition of a block of on-peak power with firm delivery at 100% delivery rate at the transmission voltage level during 06:00-22:00, Monday-Saturday. Since the quotes are for firm delivery, they include both energy and capacity.[30]

The underlying commodities for the NP15 and SP15 electricity forwards are the spot electricity at NP15 and SP15. A seller would not sign a forward contract (for example, for next month delivery) if its expectation of the next month's spot prices far exceeds the current forward price bid by a buyer. By the same token, a buyer would not sign the same forward contract if its expectation of the next month's spot prices is much less the current forward price asked by a supplier. To be sure, the transacting buyer and seller may sign the forward contract to resolve the uncertainty of the next month's spot prices. Thus, differential expectations and risk preferences among buyers and sellers lead to bilateral transactions whose price data (collected by Platts) summarize the consensus expectation of the next month's spot prices. [31]

Resource Balance Year and Transition Period

While forward prices provide market-based inference of generation avoided costs, they are only available for the next 60 future months. This provides annual market prices estimates for 2004 through 2008. Since the resource balance year is 2008, there is no need for a transition period in our base case forecast. The avoided costs of generation move from the market forward prices to the long-run all-in costs of new generation in 2008 and beyond.[32]

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[30] Put another way, the forward price contains the capacity value necessary to clear the forward market by equating forward market demand and supply. This value may be zero when market participants anticipate surplus, or positive when a shortage is expected.
[31] Siegel DR and Siegel DF (1990) The Futures Market, Probus Publishing Company, IL: Chicago.
[32] The spreadsheet developed to update the generation avoided costs allows the user to modify the resource balance year and create a transition period between market prices and Long Run Marginal Costs. The estimated market prices during the transition period are produced by a simple linear interpolation between the estimates of avoided

Long Run Marginal Cost of New Entrants

Our LRMC estimate is based on the cost to own and operate a merchant-owned combined cycle gas fired generator (CCGT) located in the California Control Area. The base case uses financing assumptions, and plant cost and performance data for a combined cycle base-load plant from a CEC August 2003 staff report.[33]

We chose the CCGT as a proxy for the LRMC of new generation based on the following findings:

10. A review of over 350 plant descriptions from the Northwest Power Planning Council (NWPPC), WECC and CEC for plants built in the last four years and in the process of being built over the next four years. Several conclusions can be drawn from this data:

    a. Most capacity that has come on line or is planned is from gas-fired generation. Gas-fired generation accounts for 73% of new or planned capacity in the US; 90% in the NWPPC area; 84% in the WECC area; and 98% in California.

    b. Combined Cycle (CCGT) plants are the dominant technology. They comprise 89% of the NWPPC area gas fired plants; 94% of planned gas fired plants in WECC area; and 87% of the gas fired plants constructed in the last 3 years or planned in California.

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costs for the last year produced from the forward market price data and the LRMC based avoided cost in the resource balance year.

[33] "Comparative Cost of California Central Station Electricity Generation Technologies" CEC Staff Final Report Aug 2003, Appendix D and Assumptions for Equity Return and Debt Interest Rates, Table 2.

c. Combustion Turbines (CT) comprise of 5% of the NWPPC area gas fired generator market. In the WECC area, of the gas-fired plants that had their technology specified, 3% of the plants planned were CTs. In California, CTs comprise 13% of the gas-fired plants.

11. A comparison of the costs of different CCGT plants revealed that, under common financing[34] and fuel cost assumptions, the levelized costs are very close. Table 3 shows how the results vary from \$50.93/MWh to \$52.67/MWh under the different cost (capital, variable and fixed O&M) and heat rate assumptions published by the EIA, [35] EPRI, [36] and CEC.[37]

Table 3: Comparison of LRMC estimates using EIA, EPRI and CEC estimates of CCGT Costs and Heat Rates.

	Levelized Cost of Capacity ($/MWh in 2008)	Annual Average Price ($/MWh in 2008)
EIA Conventional	$14.39	$52.67
EPRI Conventional	$12.50	$51.05
CEC	$14.35	$50.93

On the other hand gas price scenarios and financing assumptions are major drivers of the LRMC estimates. Table 4 shows a spread of \$46.99/MWh to \$69.32/MWh. These scenarios were generated using the CEC assumptions for the CCGT cost and performance. The natural gas prices were increased by 50% for the high gas price scenarios, and the financing period, cost of debt and cost of equity were adjusted to create the high and low financing cost scenarios. Notwithstanding the uncertainties surrounding these two input data assumptions, our

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[34] CEC August 2003 staff report "Comparative Cost of California Central Station Electricity Generation Technologies" CEC Staff Final Report Aug 2003, Assumptions for Equity Return and Debt Interest Rates, Table 2.
[35] EIA plant cost and performance data is from Table 38, page 68, of the EIA Assumptions to the Annual Energy Outlook 2002.
[36] EPRI December 2001 Technical Assessment Guide (TAG) Manual, Exhibit 5-16.

recommendation is the LRMC of a CCGT with the CEC cost, performance and financing assumptions. However, the model is designed so that the Energy Division can change the assumptions on financing and plant costs, and test different scenarios of gas prices.

Table 4: Comparison of LRMC estimates for the CEC CCGT under different financing assumptions and gas price forecasts

	Base Case: CEC cost and financing assumptions	Low Cost: Low forecasts for all major variables.	High financing cost and base case natural gas forecast	Low financing cost and high natural gas forecast	High Cost: High forecasts for all major variables
Debt Cost	7.80%	7.00%	9.00%	7.00%	9.00%
Equity Cost	16.00%	11.00%	17.00%	11.00%	17.00%
Financing years	20	30	20	30	20
Natural Gas Forecast	Base Case	Base Case	Base Case	150% of Base Case	150% of Base Case
LRMC Cost ($/MWh)	$50.93	$46.99	$51.77	$64.54	$69.32

Hourly Price Shape

We recommend using the California PX market price data from April of 1998 through April 2000 to produce hourly avoided cost shapes for NP15 and SP15. Our recommendation is driven by the following reasons:

[37] CEC August 2003 staff report "Comparative Cost of California Central Station Electricity Generation Technologies" CEC Staff Final Report Aug 2003, Appendix D.

- Data availability. During its operation, the California PX published the day-ahead NP-15 and SP-15 zonal (constrained) market-clearing prices for delivery during each hour of the following day.
- Data consistency. While there are other potential sources of hourly shapes, only the PX market data represents a period of actively traded day-ahead hourly energy products. We use the NP15 and SP15 price data as these were actively traded hubs and correspond to the wholesale market hubs from which we are getting the electricity forward prices.
- Reflection of a workably competitive market. The PX operated from April 1998 through January 2001. Our price shape construction excludes the market crises period of May 2000 through January 2001 due to price anomalies.
- Load coverage. As seen in Figure 22, the majority of PG&E's load is located near NP15, and SDG&E and SCE's loads are located near SP15.

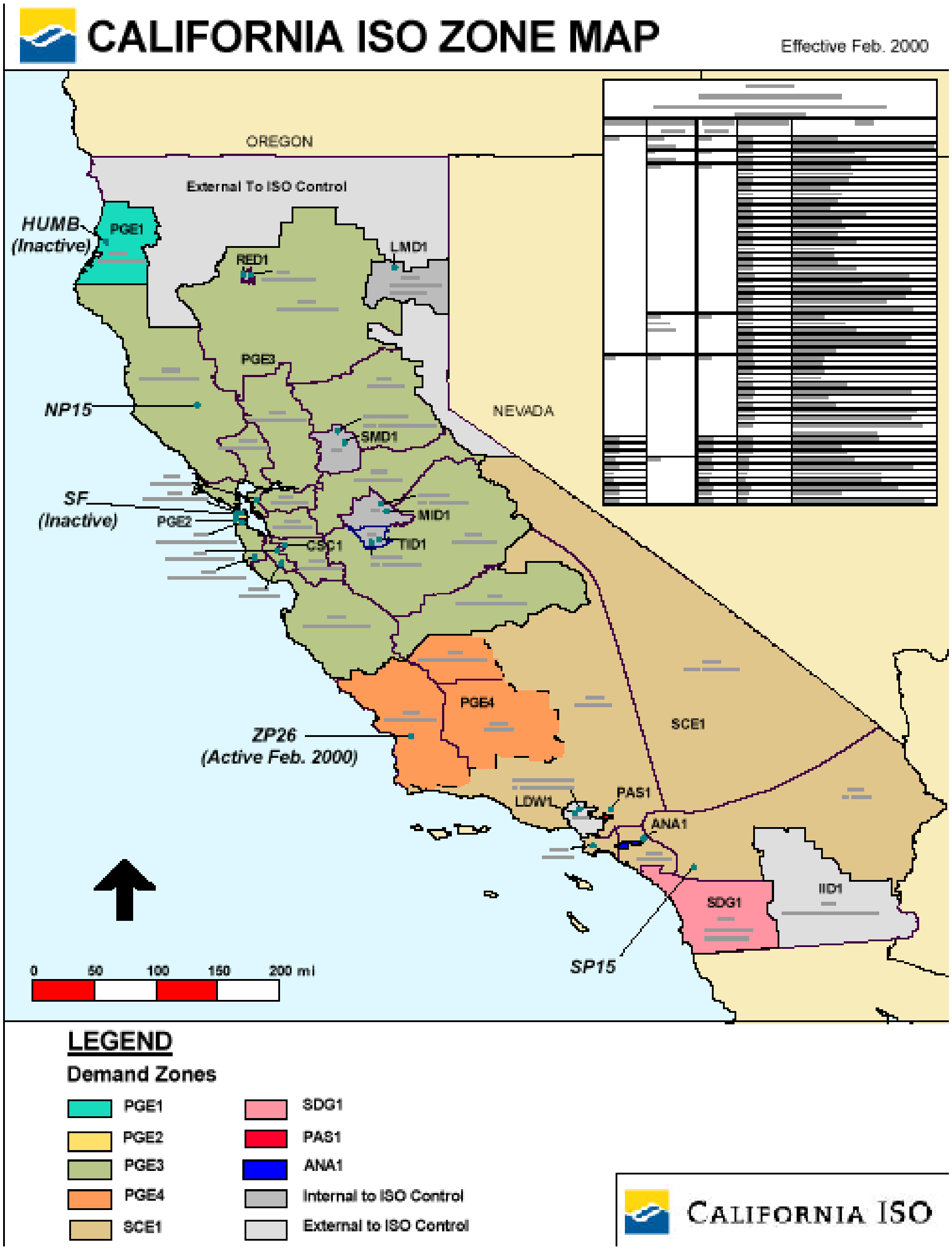

Figure 22: ISO map showing the NP15 and SP15 zones from the California ISO[38]

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[38] Source: http://www.caiso.com/marketops/technical/index.html

In selecting the 04/98 – 04/00 PX zonal price data to construct the price shape, we chose not to use the California ISO (CAISO) balancing energy market. Even though hourly price data are available for April 1998 to date, they do not represent an actively traded day-ahead energy market.

We also did not use the Platts' on-peak (06:00-22:00, Monday-Saturday) and off-peak (remaining hours) bilateral transactions because this data produces cost estimates of flat blocks by time-of-day period and therefore cannot provide hourly shapes.

2.3.3 Recommended Approach

We use two basic steps in the methodology for calculating the hourly avoided costs of generation: (1) Forecast the annual average market prices for 2004 through 2023; and (2) Allocate the annual forecast to hours of the year.

Forecasting the Annual Market Prices

We use a hybrid approach to forecast these annual market prices, which takes advantage of the publicly available market price data and cost data in three distinct periods:

1. Period 1 (Market data): This period covers the years before the California system is assumed to be in load-resource balance and during which there is active electricity forward trading and gas futures trading. This period has observable forward prices that forecast the generation (private) marginal costs.

2. Period 2 (Transition): This period contains the transition years between the end of Period 1 to the beginning of Period 3. Period 2 is calculated as a linear trend between the market price in the last year of Period 1 and the first year of Period 3.

3. Period 3 (Resource Balance): This period occurs after the California system is assumed to be in resource balance. The assumption of load-resource balance implies system supply matching demand in these years. Relatively easy entry and exit in a workably competitive market environment implies a flat supply curve defined by the LRMC, the all-in cost per MWh of new generation to meet an incremental demand profile.

Period 1: Short-term Forecast (Years 2004-2006)

We use forward market price quotes for firm delivery to determine the marginal generation costs over the period 2004-2006. We obtain these price quotes from Platts' *Megawatt Daily*. Each price quote is for the standard wholesale market definition of a block of on-peak power with firm delivery at 100% delivery rate at the transmission voltage level during 06:00-22:00, Monday-Saturday (6×16). There are no publicly available price quotes for off-peak delivery, so we estimate the average annual price by (1) assuming that the on- to off-peak ratio remains the same as the historic ratio from California PX prices; and (2) calculating the hourly weighted average of on-peak and off-peak prices for each year. Equation 3 shows the formulation for the annual price forecast.

Equation 3: Calculating the average annual price forecast from market price quotes
For years 2004 through 2006:

$$\text{Annual Average Price} = \text{Hours}_{PK} \times P_{PK} + \text{Hours}_{OP} \times P_{PK} \times \text{PXRatio}$$

Where: P_{PK} = The annual on-peak electricity price quote (where on-peak hours are defined as hours 06:00-22:00, Monday-Saturday)

PXRatio = The on-peak to off-peak ratio of electricity prices calculated from the California PX prices for 1999

Hours_{PK} = The number of on-peak hours in the year

Hours_{OP} = The number of off-peak hours in the year

Period 1: Medium-term Forecast (Years 2007)

To extend the Platts' forward price quote data beyond 2006 up to 2008, we use the NYMEX futures market for natural gas. NYMEX futures price data are monthly contracts for gas delivered to Henry Hub. As further described in Section 2.8 the NYMEX futures prices and transportation costs are used to generate forecasts of average annual delivered gas prices to generators in the California utilities' service areas. We assume a constant spark spread and use the gas price forecasts to extend the electricity price forecasts through 2007.[39] Equation 4 illustrates how we apply the percentage change in the annual gas prices forecasts to the electricity price forecast to extend the electricity prices to 2007.

Equation 4: Estimating the annual electricity price from changes in the annual gas price forecast

Annual Average Price_y = Annual Average Price_{y-1} × (Annual Average Gas Price_y / Annual Average Gas Price_y-1)

Period 2: Transition Period (2008-Resource Balance Year)

If necessary, we use a simple linear trend between the last year supported by market data (2008) and the first year of the long-term forecast. However, in the base case we have set the resource balance year at 2008 for all three utilities, so we do not have a transition period.

Period 3: LRMC of New Generation

Using the CEC assumptions on CCGT plant cost and performance, shown in Table 5, we estimate the financing, fuel, and operating costs of a merchant-owned CCGT. For each year of the forecast after resource balance we sum together the capacity cost, fixed operating costs, variable operating costs, and fuel costs of the CCGT. The fuel cost adjustments each year are a result of the forecast of annual prices for natural gas delivered to generators in the utility's service area. We do not change the heat rate assumption over the forecast period. Capital costs, fixed O&M, and variable O&M are escalated at the annual rates shown below in Table 6.

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[39] We could use the NYMEX natural gas futures to forecast the electricity prices for 2008, however, we have assumed that 2008 is the resource balance year when we switch to the long-run all-in costs of new generation.

Table 5: CCGT cost, performance, and financing assumptions used to calculate the all-in cost of new generation

Operating Data	Value
Heat rate (BTU/kWh)	7,100
Cap Factor	91.6%
Lifetime (yrs)	20
Plant Costs	
In-Service Cost ($/kW)	$616.00
Fixed O&M ($/kW-yr.)	$4.33
Property Tax (%)	1.07%
Insurance (%)	1.50%
Variable O&M ($/MWh)	$1.36
Financing	
Debt-to-Equity	60.90%
Debt Cost	7.80%
Equity Cost	16.00%
Marginal Tax Rate	39.83%

Table 6: Assumed inflation rates for CCGT capital costs and labor costs

	Gen Cap	Var. O&M	Fixed O&M
Assumed Inflation Rates	2.00%	2.00%	0.50%

Allocating the Annual Average Forecast to Hours of the Year

We use the California PX day-ahead NP15 and SP15 zonal (constrained) market-clearing prices for delivery during each hour of the following day. To reduce the impact of outlying data in any one year we use the full set of data from the pre-crises period: April 1998 through April 2000. We construct the hourly avoided cost shape by applying the following steps:

1. Map the 24 months of hourly data to the year 1999. We have 25 months of the hourly PX prices and from these we construct an annual shape. We set 1999 as the base-year,[40] and map

[40] 1999 is the only complete calendar year of PX price data that we have for the pre-crisis period.

the price data from 1998 and 2000 to 1999.[41] For example, Jan 3rd 2000 is a Monday and it is mapped to the closest Monday in 1999, which is Jan 4th 1999. In mapping the days of the week in this way, we aim to reduce mixing hours from different TOU periods and days.

2. Take the hourly average for each hour of the base year. For example, each hour in April is the average of the PX prices from the corresponding hour in April 1998, 1999, and 2000, and each hour in June is the average of the PX prices from the corresponding hour in June 1998 and 1999, etc. By averaging we reduce the impact of anomalies in any one of year of price data, albeit we are also flattening the shape slightly.
3. Calculate the annual average price from the hourly prices in the derived base year.
4. Calculate the hourly allocation factors by dividing the hourly prices in the base year by the annual average price calculated in Step 3. Figure 23 shows the average allocation factors (average day per month) for PG&E.

[41] The 1999 PX price data maps directly to the base year.

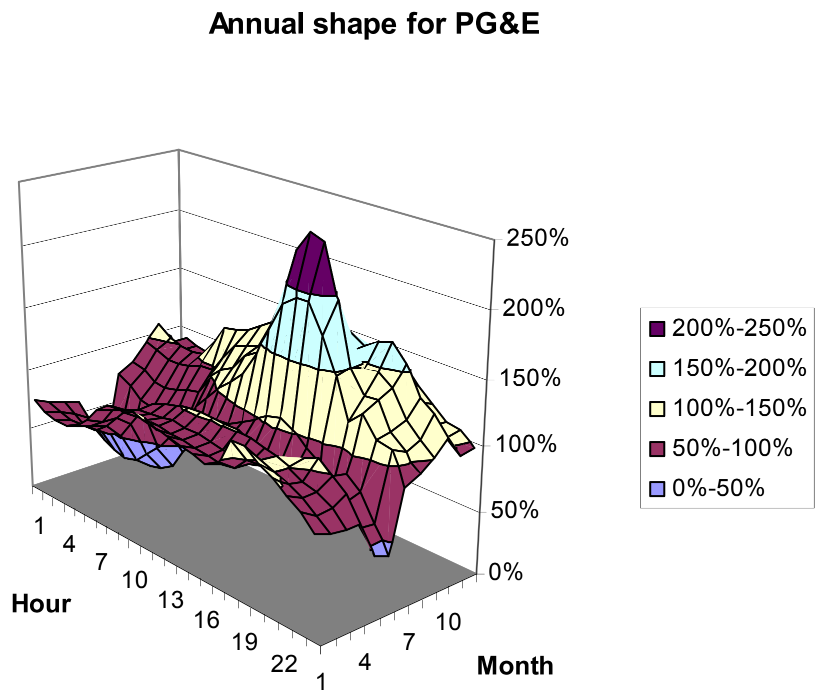

Figure 23: Hourly allocation factors for PG&E annual generation price forecasts. This shape is based on the PX day ahead constrained prices at NP15 and is shown for a typical day per month.

We then take the 20 years of annual forecasts and apply the hourly allocation factors. This gives three sets of data as the annual allocation factors differ by location (one shape for NP15 and one for SP15), and the annual average market price forecasts differ by utility.

Apply Loss Factor Multipliers

Finally we adjust the hourly avoided costs of generation to account for energy losses. Energy losses are the losses from the point of delivery at the customer with the efficiency measure to the hub on the bulk power system. The loss factors represent the average losses for each TOU period and vary by voltage level. For each hour of the year we multiply the avoided cost of generation by one plus the applicable energy loss factor. As you can see in Table 7, these losses vary by utility and voltage level, and are given by TOU period.

Table 7: Average losses by TOU period and voltage level for PG&E, SDG&E and SCE[42]

PG&E Losses

Description	Transmission	Primary	Secondary
Summer on	1.024	1.058	1.109
Summer Shoulder	1.010	1.042	1.073
Summer Off	1.012	1.036	1.057
Winter On	-	-	-
Winter Shoulder	1.012	1.039	1.090
Winter Off	1.017	1.040	1.061

SDG&E Losses

Description	Transmission	Primary	Secondary
Summer on	1.009	1.036	1.081
Summer Shoulder	1.009	1.034	1.077
Summer Off	1.007	1.027	1.068
Winter On	1.010	1.038	1.083
Winter Shoulder	1.008	1.033	1.076
Winter Off	1.007	1.027	1.068

SCE Losses

Description	Transmission	Primary	Secondary
Summer on	1.029	1.061	1.084
Summer Shoulder	1.027	1.057	1.080
Summer Off	1.025	1.050	1.073
Winter On	-	-	-
Winter Shoulder	1.027	1.054	1.077
Winter Off	1.024	1.047	1.070

2.4 Environmental Avoided Cost

This chapter estimates "[a] stream of values for the quantified environmental cost of electricity generation, in dollars/kWh, and natural gas combustion, in dollars/therm, associated with the

[42] Loss factors were obtained from: PG&E 1996 GRC, SCE 1995 GRC, and SDG&E 2004 Rate Design Window

years 2004-2023." (RFP, page 5). E3 developed separate avoided cost price streams for electricity generation (generation emissions) and natural gas combustion (consumption emissions) for use in the overall avoided cost model, as described in Section 2.2. Additionally, our team divided the environmental costs into two categories: (1) "priced" emissions defined as actual costs resulting from emission offset purchases or pollution abatement technologies and (2) "unpriced" emissions defined as environmental externality values. To the extent possible, our methodology for developing these price streams drew upon publicly available observable data to complete transparent calculations of future avoided cost price streams. In this section, we provided an explanation for those calculations or assumptions used in this analysis that are not available in the public domain.

E3's approach to calculating the environmental avoided cost streams is relatively simple. However, the assumptions underlying these calculations are important to fully understand our analyses. Our team calculated the environmental costs by multiplying an average emissions rate for the source - electricity generation plant or the gas end-use - by an average emissions price on a per pollutant basis. The key assumptions in E3's estimation of environmental avoided cost values included the following:

1. Focus on air emissions.

2. Assume gas-fired technologies are at the margin. This is consistent with the other elements of this avoided cost analysis.

3. Limit analysis to significant emissions. Assuming (1) and (2), the significant emissions that we have included in this analysis are oxides of nitrogen (NOx), particulate matter less than 10 µm (PM-10), and carbon dioxide (CO_2).

We also estimated the marginal emission abatement cost to provide an additional indication of the value of the incremental emissions. Ultimately, our team used the marginal emission abatement technology costs as a bound for the market prices included our analysis as shown in Figure 24. Therefore, the values included in this avoided cost model reflect the average market prices and emissions rates.

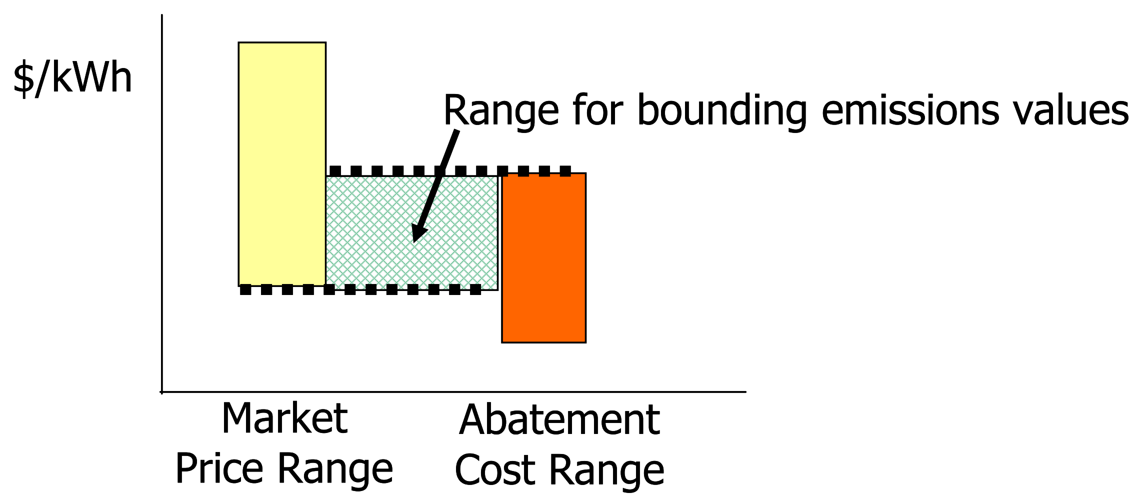

Figure 24: Using Abatement Costs to Bound Emission Market Price Data

2.4.1 Key Findings

The environmental cost chapter's key findings are:

Generation Emissions Findings

(1) The "priced" NOx and PM-10 environmental emission costs are assumed to be embedded in the market prices prior to the resource balance year as described in the Generation Section 2.3.

(2) After the resource balance year, the priced environmental costs are added to the LRMC estimate.

(3) The unpriced emission costs- or externality value of CO_2 - are included as an environmental adder throughout the analysis.

(4) Environmental costs vary by time but locational differences are not included in this estimate.

Natural Gas End-Use Emissions Findings

(1) NOx and CO_2 are included as significant source pollutants but PM-10 was excluded as a significant emission resulting from gas end-use consumption.

(2) Consumption emissions are included in the natural gas combustion avoided costs as unpriced environmental adders throughout all market price periods.

Table 8 displays a summary of the data and results E3 used to determine the environmental avoided cost values in our model. Each of these components is discussed in detail in this section.

Table 8: Summary of environmental avoided cost components

Model Inputs	Dimension	2004 (Initial) Value	Data Sources	Major Assumptions / Notes	Resulting Output applied in Model
NOx Market Prices	**Annual ($/lb)**	**$3.50/lb NOx**	**South Coast Air Quality Management District (SCAQMD) - RECLAIM Data**	**Assumed market prices apply to all of California**	**$/MWh**
PM-10 Market Prices	**Estimated Annual ($/lb)**	**$4.90/lb NOx**	**California Air Resources Board (CARB)**	**Estimated using CARB ERCs and RECLAIM Prices**	**$/MWh**
CO_2 Market Prices	**Estimated Annual ($/lb)**	**$0.004/lb CO_2**	**Existing International Markets, Oregon Climate Trust, Utility Planning Documents, Models**	**Used US and International market estimates to calculate future CO_2 emission costs**	**$/MWh**
Emission Factors	**lb/MMBtu**	**Varies. See individual pollutant discussions below.**	**Environmental Protection Agency (EPA), California Energy Commission (CEC)**	**Averaged (calculated by electricity generation or natural gas consumption technology)**	**$/MWh**
Abatement Costs	**$/pollutant removed**	**Varies. Value used to test reasonableness of market price data**	**Industry Reports; Vendors; CARB**	**Averaged by abatement technology**	**N/A**

In this chapter, we first explain our approach to calculating the environmental avoided cost adder. Then we discuss the emissions rates (electric generation and natural gas consumption rates) followed by our calculation of emission costs for each of the three pollutants (NOx, PM-10, and CO_2) included in our analysis. We bring the rate of emissions together with the costs to enable a discussion of our findings for environmental avoided costs over the 20-year time horizon. Finally, we provide additional background information regarding the inclusion of CO_2 in this analysis.

2.4.2 Approach to Environmental and Externality Estimates

In contrast to the existing CPUC avoided emissions costs, E3 categorized environmental costs into priced and unpriced emissions, which are accounted for separately in this avoided cost analysis. The priced emissions refer to those emissions that are regulated and for which energy generators must purchases some type of allowances or credits to offset the impact of the emissions produced from their operations. The unpriced emissions represent an externality that is not presently embedded in energy prices and is added directly to the generation and T&D avoided costs. The steps we took to calculate the environmental costs are described in detail throughout the remainder of this section, where we discuss emission rates for both generation plants and gas end-use followed by a description of our calculation of emission costs. The emissions values included in the avoided cost model are the product of the average emission rates during specific hours of the day times the cost of emissions as shown in Figure 25.

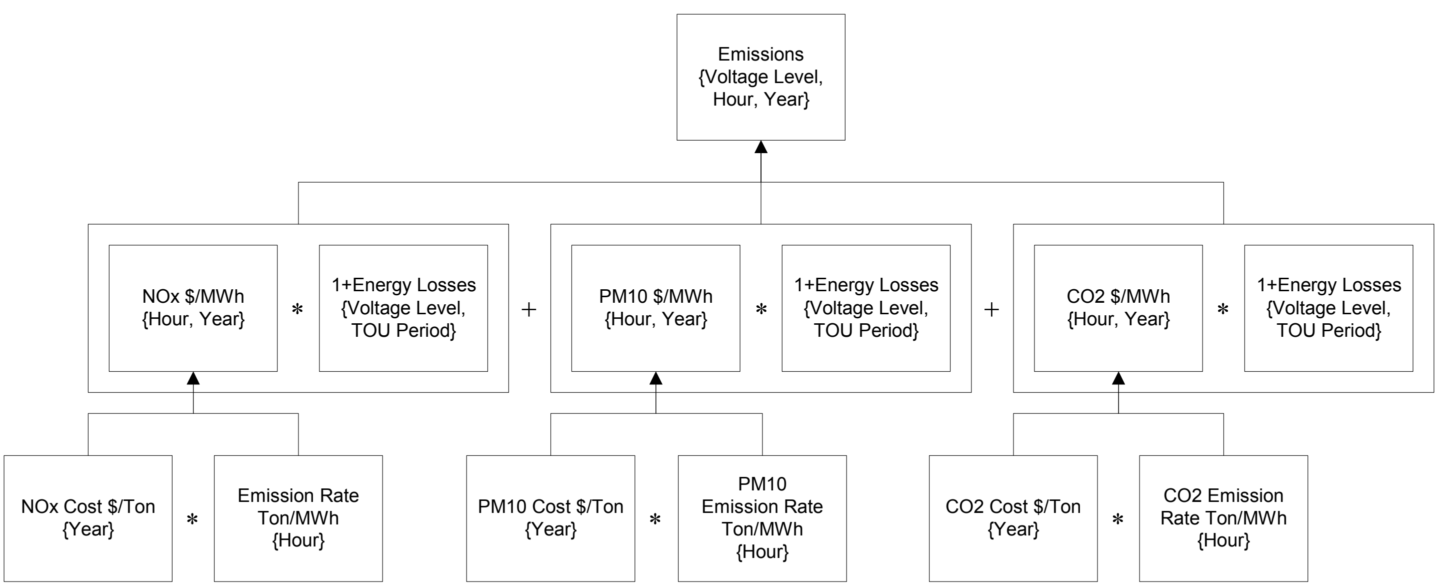

Figure 25: Environmental avoided cost calculation

Before delving into the specifics of each pollutant, it is important to note that our team decided to address environmental costs on a statewide basis rather than incorporate regional price differences. We recognize that regional differences in value exist in different air basins across the state depending upon their air quality attainment status and other pertinent factors. We explored the possibility of modeling these differences. However, given the limited emission cost data available presently, we did not believe we could accurately reflect price differences in this type of modeling effort. In the future, as the California emissions markets become more robust, we would recommend incorporating regional price differences into this model.

2.4.3 Environmental and Externality Estimates

Discussed below is the process we undertook to estimate actual environmental costs and environmental externalities. The first half of this section outlines the emissions rates and the second half outlines the emissions costs. We multiplied the emissions rates by the emissions costs to arrive at the environmental avoided cost value streams on a per pollutant basis used in the overall avoided cost models.

Generation Emission Rates

Our team calculated average emissions rates using publicly available generating plant permit data such that if a major technology shift occurs in the future, this information can be readily updated. We compiled the reported and permitted emission rates for NOx and PM-10 for over 15 plants in California included emission estimates for aging plant in California.[43] Since

[43] See Appendix B for references to generation plants reviewed in this analysis.

emission rates vary for both NOx and PM-10 depending upon the operating configuration and the type of abatement control technologies installed on the generating system, we addressed each of these separately in our analysis. We determined the CO_2 emissions rates using the implied heat rate of the plant at the margin in any given hour. It was possible for us to calculate CO_2 emissions this way because the emissions are a direct function of the fuel type employed. No abatement technology exists for CO_2, and combustion of natural gas is independent of plant configuration other than efficiency. Additionally, generation plant emission rates do not vary in a consistent pattern for plants in different climate zones or regions so we elected to exclude location as a factor in our emission rates determination. We describe below how we determined the average emission rates for NOx, PM-10, and CO_2.

NOx emission rates. Using the NOx emission rates reported for existing, new, and proposed natural gas-fired combined cycle and simple cycle plants located in California, we were able to obtain a relevant range of emission rates to include in our analysis. As NOx emissions vary as a direct result of the installed abatement technology, it is difficult to determine a specific emission rate that would be representative of a typical plant in a particular hour. Therefore, we plotted the reported emission rates relative to the implied plant heat rate and observed that while there is plant-specific variation in the emission rates, average rates relative to heat rate can be calculated with reasonable accuracy. Figure 26 shows NOx emission rates relative to generating plant average heat rates. There is a clear difference between emission rates of higher efficiency plants versus lower efficiency plants. This is likely due to the often prohibitive expense of retrofitting older, and often less efficient plants, with best available control technologies (BACT), resulting in emission rates that meet area regulations but are no lower than required.

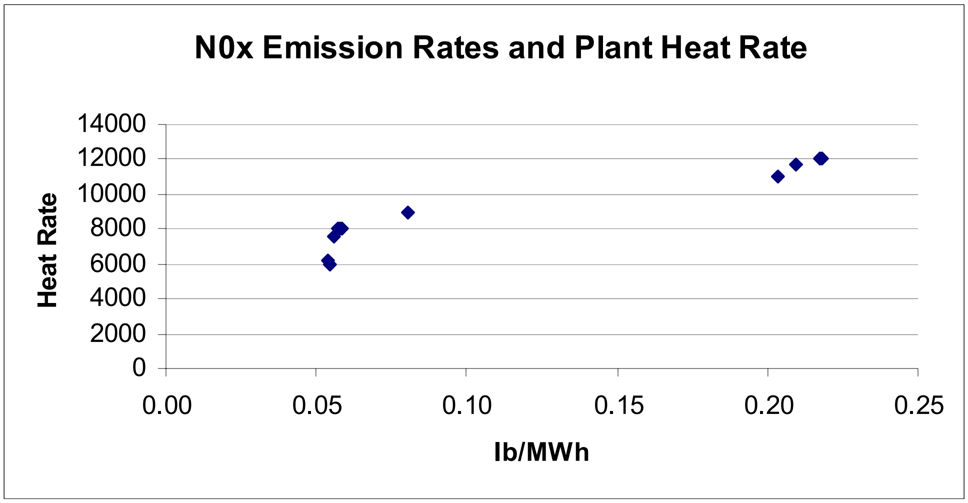

Figure 26: NOx emission rate and plant heat rate

PM-10 emission rates. We used similar NOx emission rate data sources to obtain PM-10 emission rate information.[44] By employing best combustion practices and controls and using clean burning natural gas, generators are able to reduce the amount of PM-10 emissions from their plants. In determining an average PM-10 emission rate for each hour, we used the same method as for the NOx evaluation. We plotted the PM-10 emission rates against the reported average heat rates for both baseload and peaking plants in California. The range of PM-10 emission rates did not vary as widely as for the NOx emission rates primarily because the combustion controls and natural gas fuels are more consistent on a plant by plant basis than NOx controls. Figure 27 displays the range of PM-10 emission rates relative to plant heat rates.

[44] See Appendix B for references to generation plants reviewed in this analysis.

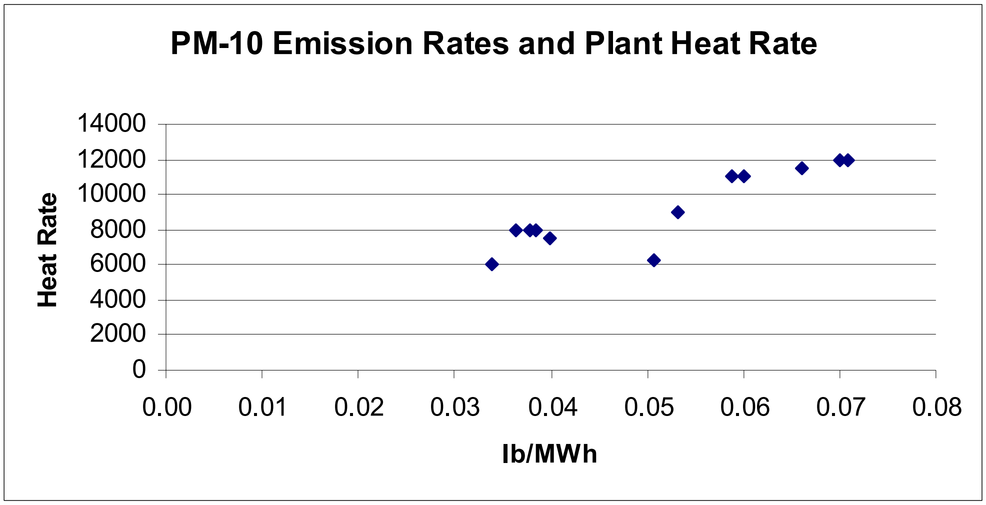

Figure 27: PM-10 emission rates and plant heat rate

CO_2 emission rates. We calculated the CO_2 emission rates for each plant directly from the reported heat rate. This is a simple mass balance equation since no abatement technologies exist for CO_2 emissions today. We used the following equation to determine the emission rates:

$$CO2\_Emissions = CI * HR$$

Where: CI = Carbon Intensity of Natural Gas (117 lb CO_2/MMBtu)[45]

HR = Heat Rate (Btu/kWh)

[45] US EPA – natural gas emission rates roughly = 117 lbs CO2/MMBTU (assuming a 95% conversion to CO2)

Therefore, when we plot the CO_2 emission rates relative to heat rate, we see straight-line relationship as shown in Figure 28.

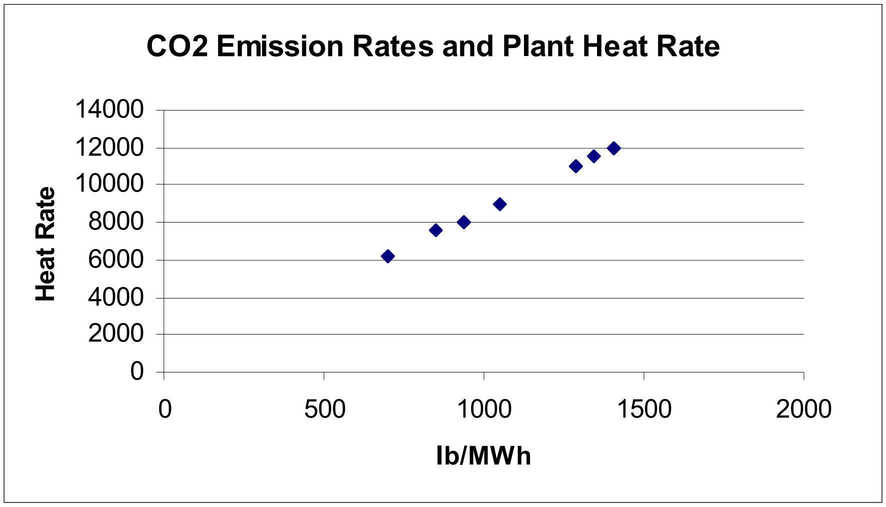

Figure 28: CO2 emission rates and plant heat rate

Natural Gas End-Use Emission Rates

Emissions that result from natural gas consumption are varied and disperse in nature. In determining the emission rates for gas consumption uses, we used the average emission rates provided in the EPA AP-42 for several different boiler categories, with and without emission control technologies[46]. Table 9 displays the emissions rates for NOx and CO_2 as reported by the EPA. For the consumption emission rates, we excluded PM-10 as a significant pollutant because

[46] EPA AP-42, Fifth Edition Volume 1, Chapter 1 External Combustion Sources, Section 1.4: Table 1.4-1

the levels of PM-10 emissions are so low that they would be inconsequential to the overall consumption emission analysis.[47]

Carbon monoxide is not included as a significant pollutant because it typically arises only if the equipment is not working properly. In this analysis, we assume the gas end-use equipment is in working order.

Table 9: Natural gas end-use emission rates for NOx and CO_2[48]

Combustor Type (MMBtu/hr heat input)	Controls	NOx (lb/MMBtu)	CO2 (lb/MMBtu)
Large Boilers			
(>100)	Uncontrolled	0.186	117
	Controlled Low NOx Burner	0.137	117
	Controlled – Flue Gas Recirculation	0.098	117
Small Boilers			
(<100)	Uncontrolled	0.098	117
	Controlled Low NOx Burner	0.049	117
	Controlled – Flue Gas Recirculation	0.031	117
Residential Furnaces			
(<0.3)	Uncontrolled	0.092	117

Generation Emission Costs

To calculate our environmental avoided cost value stream, we developed estimates of emission costs from existing market data. Again we used available market data to provide reasonable estimates of the value of avoiding emissions. We estimated prices for NOx, PM-10, and CO_2 using market data from the RECLAIM NOx market, the CARB ERC PM-10 market and regional

[47] EPA AP-42, Fifth Edition Volume 1, Chapter 1 External Combustion Sources, Section 1.4: Table 1.4-2
[48] EPA AP-42, Fifth Edition Volume 1, Chapter 1 External Combustion Sources, Section 1.4: Table 1.4-2

and global CO_2 markets and models respectively. We discuss the costs of each pollutant separately below.

NOx Emission Costs

Southern California has an active market for discrete (marginal) NOx trading credits in the Regional Clean Air Incentives Market (RECLAIM) operated by the South Coast Air Quality Management District (AQMD).[49] The RECLAIM trading credit (RTC) market, while regional, provides the best estimate of what generators are willing to pay to offset their emissions under today's regulatory climate. This market not only provides current prices but also future NOx RTC prices through 2011 as illustrated in Figure 29. Table 10 shows the actual prices reported for NOx RTCs through 2010. After 2011, we forecasted the growth of the RTC prices through 2024, which is discussed further in later in this section.

[49] *http://www.aqmd.gov/reclaim/rtc_main.html*

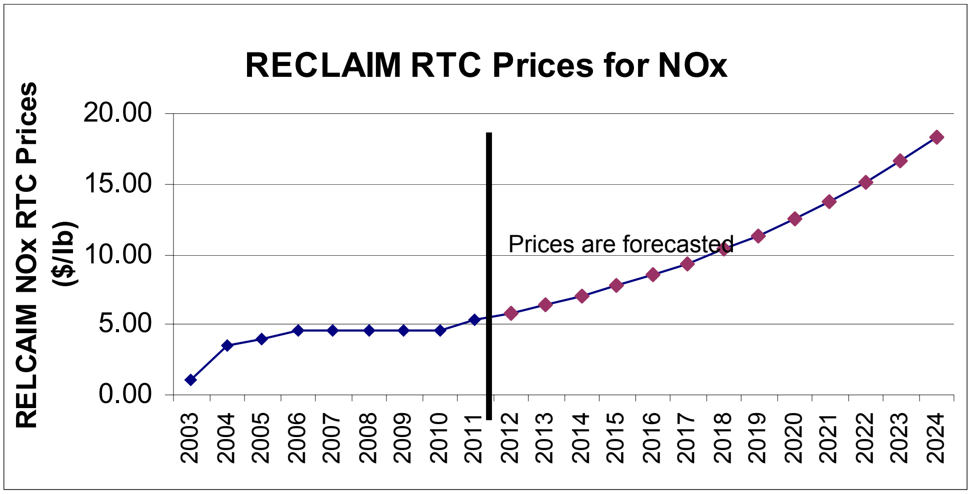

Figure 29: AQMD RECLAIM RTC prices

Table 10: NOx RECLAIM RTC prices through 2010

NOx RECLAIM Prices	2004	2005	2006	2007	2008	2009	2010
($/lb)	$ 3.50	$ 3.94	$ 4.55	$ 4.63	$ 4.63	$ 4.63	$ 4.63

PM-10 Emission Costs

The market information available for PM-10 credit prices is not as transparent as the prices for NOx in California. We collected most recent the market data available for PM-10 emissions values primarily from the California Air Resources Board (CARB) and regional air district offset transaction market. Offsets, however, do not represent discrete quantities of emissions credits for a particular vintage but rather are valid credits for permanent reductions in emissions produced. For our purposes, in determining the discrete avoided cost of PM-10 emissions for program evaluation, this value does not easily translate into an appropriate measure of the marginal value of PM-10. We addressed this issue by electing to use both the CARB emission offset transaction reports and the RECLAIM RTC market information to annualize the PM-10 emission reduction credit (ERC) prices and determine a discrete price for PM-10 emissions mitigation.

Specifically, we used the most recent average CARB emission reduction credit (ERC) prices as a baseline price for both PM-10 and NOx. We took a ratio of the PM-10 ERC prices to the NOx ERC prices to get a relative relationship between the actual credit prices. We then multiplied the RECLAIM RTC values for NOx by the PM-10-to-NOx ratio to arrive at a discrete PM-10 market value for a pound of emissions reduced. Table 11 shows the resulting values of the annualized PM-10 prices through 2010. We tested several other methods of annualizing the CARB ERC values for PM-10 and found similar results as shown in Table 11. However, this method proved to be the most transparent and robust way to capture the values that have been expressed the existing emissions market.

Table 11: Annualized PM-10 ERC prices through 2010

PM-10 Annualized ERC Prices	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*
($/lb)	$ 4.90	$ 5.51	$ 6.37	$ 6.47	$ 6.47	$ 6.47	$ 6.47

CO_2 Emission Costs

Estimating the value of CO_2 emissions is the most subjective element to this analysis because no market exists in California to capture this "unpriced" emission or externality. Therefore, we looked to publicly available data in regional markets such as Oregon and the Oregon Climate Trust, PacifiCorp's Integrated Resource Plan, and other state values of CO_2. Additionally, we evaluated many of the existing technical-economic and macroeconomic models for estimating the price of CO_2 credits as a result of the pending implementation of the Kyoto protocol in Europe and effects of United States participation. A more detailed discussion of the models and our conclusion is included in Section 2.4.4. However, our initial estimate of the CO_2 value in 2004 is \$8/ton CO_2. Table 12 shows the price estimates used in our analysis through 2010 in \$/lb CO_2.

Table 12: CO_2 price estimates through 2010

CO2 Price Estimates	*2004*	*2005*	*2006*	*2007*	*2008*	*2009*	*2010*
(\$/lb)	\$ 0.004	\$ 0.004	\$ 0.004	\$ 0.005	\$ 0.005	\$ 0.005	\$ 0.005

Natural Gas End-Use Emission Costs

The emission costs for gas end-use consumption are valued as "unpriced" externalities in this avoided cost model because most end-users are not required to outright purchase credits to offset their gas consumption and thus it is not a direct cost or "priced" emission in our model. We applied the same market prices for calculating the consumption emission costs as we do for the generation emission costs as discussed previously in this section.

Emission Rates and Costs

Finally, prior to including the emissions values in the overall avoided cost model, we simply multiplied the emission rates by the estimated emission cost per pollutant. We summed these values based on plant heat rate for the base year of 2004 to arrive at the values shown in Figure 30. Because the CO_2 emission rate is significantly higher than the NOx and PM-10 emission rates, the slope appears linear with respect to heat rate.

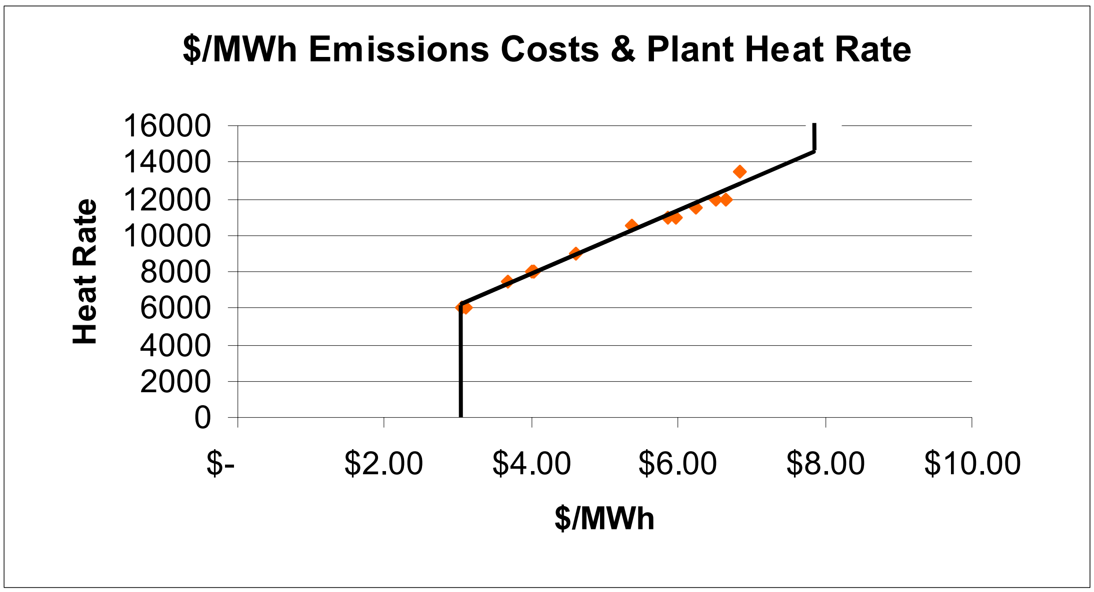

Figure 30: Emission costs ($/MWh) and plant heat rate for base year (2004)

When incorporating emissions avoided costs into the model, we specified a heat rate floor and ceiling that mirror the average range of operation for generating plant efficiencies. These are flexible boundaries whereby the heat rate floor and ceiling can be shifted over time as efficiency improvements in the generation technologies or generating plant mix changes occur. In each case, the cost of emissions associated with the floor or ceiling heat rate is used for any implied heat rate outside of our identified range. For example, our heat rate floor is 6,240 Btu/kWh so for any implied heat rate lower than this floor, the emissions costs would appear as if the heat rate were still at 6,240 Btu/kWh. Similarly, for any implied heat rate greater than 14,000, the emissions cost input in the model would remain at the level associate with a generation plant with a heat rate of 14,000 Btu/MWh.

Again we calculated the emissions costs for gas consumption end-uses in a similar fashion. However, we did include an estimate of varying efficiencies for the consumption end-uses as these emission rate values do not vary over the course of the day or year in the same way as do electrical generation sources.

Reasonableness of Results

E3 recognizes that using the limited available market data to calculate environmental values may not as transparent as using market data for other parts of this analysis. However, we assert that although these markets are fairly new, they still represent the most transparent price signals available today and will be a useful data source of the 20-year period of this analysis. As discussed earlier, our way of checking the reasonableness of our market-based results was to use determine if pollution abatement costs were lower than our market credit costs. Costs of abatement technologies alone are fairly consistent but estimating the costs of retrofitting that same equipment to an existing facility can vary widely. We surveyed several sources (identified in Appendix B) which indicated that our market-based emissions cost results were typically below those of most retrofit options for NOx. Little relevant data regarding PM-10 and CO_2 abatement technologies is available other than reconfiguration of a generating system or fuel switching respectively. Therefore, we believe that the methodology discussed above represents the best available estimate of environmental emissions and externality costs.

Forecasting the Environmental and Externality Values

A robust futures market does not yet exist for emission credits. While the RECLAIM market represents the most forward-looking market price signals, the availability of this data source ends in 2011. Therefore, while we were able to draw on the available baseline market data, we had to forecast the prices for discrete emission credits for the duration of our study horizon. We looked at the projected growth in the NOx RECLAIM RTC market and used this annual price growth level as proxy for future growth. In the case of RECLAIM, the RTC prices increased on average over 12% per year. However, to account for a significant price spike in near-term years, we lowered the annual growth rate to 10% per year. The 10% growth was applied to both the NOx RECLAIM RTC prices and the PM-10 prices after 2011 when future RTC credit prices are no longer observable.

In the case of CO_2 credits, we escalated the baseline price by 5% annually based upon the anticipated market projections and the model results discussed in the next section. Again, emission price growth can easily be adjusted as the emissions markets mature and better data becomes available.

2.4.4 Why Consider CO_2?

Unlike the criteria pollutants such as NOx and PM-10 that are regulated under the Federal Clean Air Act and corresponding State legislation, CO_2 is not consistently regulated at either the federal or state levels. We recognize that CO_2 costs are not included in the marginal cost of producing electricity or thermal energy from natural gas today, and that CO_2 is strictly an unpriced externality. However, the CPUC is specifically directed to address the potential financial risks of CO_2 in the avoided cost methodology as stated in the finding of fact of Rulemaking 01-10-024. It states that "We should refer the question of potential financial risks associated with carbon dioxide emissions to R.01-08-028, to be considered in the context of the avoided cost methodology -- as part of the overall question of valuing the environmental benefits and risks associated with utility current or future investments in generation plants that pose future financial regulatory risk of this type to customers."[50]

Given the 20-year time frame of this avoided cost analysis, we consider it highly likely that CO_2 will be regulated and become part of the marginal cost of using fossil fuel during the time period of the analysis. The reasons for expecting that will come under emission limits, and thus take on costs for emission charges, emission allowances, or abatement measures, include the following:

- The challenge of climate change is here to stay. The Intergovernmental Panel on Climate Change (IPCC), a highly visible international science effort examining the science of climate change and its impacts, found in its latest report on climate change that "*it is not a question of whether the Earth's climate will change, but rather when, where and by how much,"* and that *"most of the warming observed over the past 50 years is likely to*

[50] California Public Utilities Commission, Proposed Decision of ALJ Walwyn, Rulemaking 01-10-024, November 18, 2003, Findings of Fact #64, pp. 223.

have been due to the increase in GHG concentrations."[51] The U.S. National Research Council's (NRC) Committee on the Science of Climate Change found that "the IPCC conclusion that most of the observed warming of the last 50 years is likely to have been due to the increase in GHG concentrations accurately reflects the current thinking of the scientific community on this issue. Despite . . . uncertainties, there is general agreement that the observed warming is real and particularly strong within the past 20 years."[52]

- The Kyoto Protocol to the UN Framework Convention on Climate Change was signed by 84 countries, including the United States, and has been ratified by 120 countries. It will go into force only if either Russia or the U.S. ratifies, although at present, neither country indicates they will ratify the Protocol. Even though the quantitative goal of the Kyoto Protocol, to reduce greenhouse gas (GHG) emission from industrialized countries by 7% between 1990 and 2008-2012, is now unlikely to be achieved, the treaty is nevertheless a clear statement of international commitment to mitigate climate change.

- Several US states have now regulated or are considering regulation of CO_2 and other GHGs in some form. Several northeastern states have proposed to create a regional GHG cap-and-trade market system, and eleven states recently sued the US EPA over its refusal to regulate CO_2 under its Clean Air Act authority. California enacted legislation to limit CO_2 emissions from cars. Most relevant to this analysis, Oregon *now requires new power plants to meet a CO_2 emission standard to receive a site certificate*. This standard is so

[51] Intergovernmental Panel on Climate Change Working Group 1, 2001. *Third Assessment Report Summary for Policymakers.* http://www.ipcc.ch/

stringent that developers of combined-cycle power stations must offset some portion of their CO_2 emissions. Offsets can be obtained by direct investment, by purchases on the open market, or by funding the Oregon Climate Trust, which serves as the standard's monetary compliance path.[53]

- There is now active international GHG trading among EU countries. The UK, Denmark and the Netherlands have begun various forms of GHG trading. The World Bank's Prototype Carbon Fund (PCF) has been assembling carbon offset projects for five years.

- Although the current administration opposes Kyoto ratification and GHG limits, there is legislative support in both major parties for climate change mitigation, as indicated by the 2003 Senate debate on the McCain-Lieberman bill, which received 43 Senate votes.[54]

Thus, it appears that regulation of CO_2 and other GHGs is a matter of when, not if. The eventual GHG regulation will almost certainly be market based; involving some sort of cap-and-trade or carbon offset market. Obtaining emission allowance or offsets, paying emission charges, or complying with emission limits will impose a cost of electric utilities and other energy suppliers. The main argument the current administration makes against GHG limits is based on the costs to the energy industry. While there is much disagreement about the magnitude of these costs and the potential for low-cost GHG reductions, we are confident that the eventual GHG limits will

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[52] National Research Council, *Committee on the Science of Climate Change, Division on Earth and Life Studies. Climate Change Science: An Analysis of Some Key Questions,* National Academy Press, 2001. http://www.nap.edu
[53] See www.climatetrust.org
[54] Climate Stewardship Act, United States Senate Bill, S.139, Sponsored by John McCain and Joe Lieberman, 2003

add to the marginal costs of the production and delivery of electricity and natural gas in California.

CO_2 Markets and Abatement Costs: Modeling Comparison

A great deal of research and analysis has been conducted on future costs of greenhouse gas (GHG) emission reductions and resulting prices in emission trading markets. Unfortunately, however, there continues to be substantial disagreement among studies that focus on the costs of reducing carbon dioxide emissions from fossil fuel electricity generation. Technical-economic (bottom-up) models identify substantial cost-effective emission reduction potential in most countries, albeit under the assumption that existing barriers to energy efficiency can be reduced. The models find the total emission reduction potential in most industrialized countries over the next decades being estimated at 10 to 30 percent, with no or little cost to society; the emission reduction potential increases if higher costs are accepted. Similar potential has been identified in several developing countries.[55]

Studies based on macroeconomic (top-down) models, on the other hand, generally conclude that significant macroeconomic losses would result from the imposition of carbon emission limits. The energy-policy measures that these models evaluate are energy-price changes through, for example, carbon taxes. As modeled in top-down analyses, such energy price alterations result in a transfer of production inputs to less energy-intensive economic sectors, revenue increases to governments, and an economic efficiency loss to society. Other policy interventions (e.g., regulations and measures aimed at overcoming barriers to energy-efficiency improvements) are assumed to be expensive and sub-optimal, because they are not part of the assumed economically-efficient baseline.

In comparing these two approaches, one sees commonalities and points of disagreement. Top-down modelers suggest that a direct tax on carbon emissions, channeled through general government spending and large enough to constrain emissions, would be an expensive strategy. Many bottom-up analysts would probably agree, recognizing that market barriers to energy-efficiency improvements would inhibit an optimal response. Both groups would likely agree that a tax, perhaps revenue neutral or channeled to investment, to slowly increase the price of energy would capture the many environmental and other externalities from energy use. The bottom-up models, however, identify additional emission reduction potential under the assumption that the barriers to energy efficiency can be reduced.[56]

E3 used these viewpoints in establishing robust estimates of future CO_2 cost implications given the present California context. Starting with the bottom-up view, a comprehensive study of carbon emission-reduction options by the DOE national laboratories concluded that U.S. emissions of CO_2 could be returned to the 1990 level by the year 2010 with a range of familiar policy instruments, supplemented by a carbon emission tax or permit market price of $50/mtC

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[55] Intergovernmental Panel on Climate Change (IPCC), 1996. *Economic and Social Dimensions of Climate Change*. Cambridge University Press.
[56] See, for example, Krause, F., et al, 2001. Cutting Carbon Emissions at a Profit: Opportunities for the U.S., International Project for Sustainable Energy Paths, El Cerrito CA, www.ipsep.org, and Swisher, J.N., 1996. "Regulatory and Mixed Policy Options for Reducing Energy Use and Carbon Emissions," *Mitigation and Adaptation Strategies for Global Change,* vol. 1, pp. 23-49.

(\$12.5/ton-CO_2).[57] The technical measures that would meet this cost criterion include a range of energy-efficiency measures, predominantly in the commercial sector. On the supply side, the dominant measures would be co-firing of biomass fuel in coal-fired generating plants, as well as wind turbines in favorable sites.[58]

Moving onto top-down studies of reducing CO_2 emission costs in the U.S., some of the most comprehensive recent work is from the well-known Energy Modeling Forum (EMF) at Stanford University. This group recently produced a systematic comparison of 13 modeling analyses of GHG emission reduction costs. The modelers were asked to analyze a standardized set of emission reduction scenarios over the period 1990-2050, using common assumptions for selected parameters, including gross domestic product (GDP) and GDP growth rate, population and growth rate, the fossil fuel resource base, and the cost and availability of long-term supply options. The modelers also used carbon taxes, based on the carbon content of fossil fuels, to achieve emission reductions.[59]

The EMF model results estimate that a tax of about \$5-\$37.5/ton-CO_2 is required to hold emissions at 1990 levels in 2010, assuming no emission trading, and the median estimate was

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[57] Interlaboratory Working Group, 2001. *Scenarios for a Clean Future*, ORNL-476 and LBNL-44029, Oak Ridge National Laboratory (ORNL) and Lawrence Berkeley National Laboratory (LBNL); and the earlier version: Interlaboratory Working Group, 1998. *Scenarios of U.S. Carbon Reductions: Potential Impacts of Energy-Efficient and Low-Carbon Technologies by 2010 and Beyond*, ORNL-444 and LBNL-40533, Oak Ridge National Laboratory (ORNL) and Lawrence Berkeley National Laboratory (LBNL).
[58] This wind power is assumed to be produced at a busbar cost of less than \$40/MWh, thus accounting for the rather small cost premium.
[59] See the special Kyoto issue of the *Energy Journal*, May 1999, summarized in J. Weyant and J. Hill, pp. vii-xliii. The EMF study included CETA (Peck and Teisberg), CRTM (Rutherford), DGEM (Jorgensen and Wilcoxen), ERM (Edmonds and Reilly), Fossil2 (Belanger and Naill), Gemini (Cohan and Scheraga), Global2100 (Manne and Richels), Global-Macro economy (Pepper), Goulder, GREEN (Martins and Burniaux), IEA (Vouyoukas and Kouvaritakis), MARKAL (Morris), MWC (Mintzer), and T-GAS (Kaufmann).

\$18/ton-CO_2. Estimates of carbon taxes required to reduce emissions 7% below 1990 levels by 2010 (i.e., Kyoto Protocol compliance) range from \$12.5-\$69/ton-CO_2 with no trading, and the median estimate was \$46/ton-CO_2.

Several of the EMF models also explored the effects of international carbon emission trading on emission reduction costs. As expected, unrestricted trade increases the range of reduction measures and reduces the costs of reductions. In these studies, the carbon tax for Kyoto compliance fell from \$168-\$275/mtC (\$42-\$69/ton-CO_2) with no trade to \$22-218/mtC (\$5-\$55/ton-CO_2) with Annex I trading only and \$21-31/mtC (\$5-\$8/ton-CO_2) with unlimited global trade. The latter values correspond to the minimum price for carbon emission permits on the global market. Any transaction costs or restrictions on trading would reduce the volume of trade and increase costs. The median estimate for Annex I trading was \$17/ton-CO_2.[60]

By comparing the above sources of emission reduction cost estimates, E3 next attempts to define a range of trajectories for marginal reduction costs and CO_2 emission offset prices, starting with the following summary observations:

- Macroeconomic (top-down) studies of Kyoto-compliance scenarios report marginal reduction cost levels and market-clearing prices for domestic emission-trading markets on the order of \$40/ton-CO_2 and more. However, some studies' results are below \$15/ton-CO_2, and the median values for returning to 1990 emission levels and for Kyoto compliance with Annex I trading indicate values of about \$70/mtC (\$17.5/ton-CO_2) under plausible future international emission reduction regimes.

- Bottom-up studies suggest that a carbon emission tax or permit price on the order of \$12.5/ton-CO_2 would be necessary to return to 1990 levels. Based on the top-down model results suggesting that the marginal costs of Kyoto compliance with Annex I trading would be similar to that of 1990 emissions without trading, we estimate that the bottom-up models would project costs for Kyoto compliance with Annex I trading to be in a similar range around \$12.5/ton-CO_2.

- Generic project cost data for representative energy (supply and demand-side), land-use and methane emission reduction measures indicate that a significant quantity of potential carbon offsets involving methane emission recovery (from landfills and agriculture) and carbon sequestration (in land-use and forestry initiatives) would cost only about \$1-3/ton-CO_2, but that even low-cost (\$10-20/MWh) energy-sector measures would cost on the order of \$20/ton-CO_2.

- Reported costs of CO_2 emission offset projects identified to date vary widely, with a median cost of about \$7.5/ton-CO_2.

- The results of the recent Dutch carbon offset tenders, the UK trading market, and the World Bank's recent PCF projects suggest a carbon offset price of \$7.5/ton-CO_2.[61]

Based on the above observations, E3 can project marginal emission reduction costs and market-clearing prices for carbon emission credits in the 2005-2010 timeframe;

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[60] Annex I countries are the industrialized countries including U.S., Japan, and western and eastern Europe.

- A reasonable short-term value for CO_2 emission reductions is about \$5/ton-CO_2, based on the World Bank PCF purchases and Dutch and UK market activity.

- U.S. and international efforts to comply with the Kyoto Protocol, even if incomplete and not fully successful, would drive the price of carbon emission credits toward a range of \$12.5/ton-CO_2 by 2008 and \$17.5/ton-CO_2 by 2013.

If one discounts the projected stream of shorter term \$5/ton- CO_2 trending to 12.5/ton- CO_2 by 2008 and to 17.5 /ton- CO_2 by 2013, at a 8.15% discount rate, the present values are about \$7.5/ton-CO_2. This estimate is sufficiently close to the existing \$8 that E3 concludes that a reasonable and conservative, albeit uncertain, value for CO_2 emissions is to retain the existing \$8/ton-CO_2 used in the current avoided cost estimates.

2.5 Transmission & Distribution Avoided Cost

The CPUC requires "a stream of values for the quantified cost of electricity and natural gas transmission and distribution (T&D) upgrades and maintenance, in dollars/kWh and dollars/therm respectively, on an annual basis, associated with the years 2004-2023." (RFP, page 6) Because the avoided costs depend upon area-specific capacity conditions as well as individual utility planning criteria and practices, we have relied on investment and load growth data and financial assumptions provided by Pacific Gas & Electric (PG&E), Southern California

[61] The Dutch program is reported at www.senter.nl, and the PCF at www.prototypecarbonfund.org.

Edison (SCE), San Diego Gas & Electric (SDG&E) and Southern California Gas (SoCal Gas) to develop the forecasts. In most cases, the needed information is developed by the utilities as part of their normal regulatory filings.

The T&D avoided cost forecasts in this report differ from the existing values contained in the *Policy Manual* in several important ways. Whereas the stream of annual electric T&D values in the *Policy Manual* is based on a statewide average of weighted forecasts of avoided T&D costs across utility service territories, E3's forecasts are area- and time-specific. E3 has cross-mapped each utility's electric distribution planning areas to the 16 climate zones specified by the CEC's Title 24 building standards and allocated the annual forecast electric T&D avoided costs to the hours of the year that are the most likely drivers of the local peak demand.[62] This approach allows the Commission to attribute greater value to DSM programs that 1) are implemented in areas with higher avoided costs; and 2) provide reductions when they are most needed --- at the time of the peak load, as opposed to measures that affect off-peak consumption. Figure 31 illustrates the climate zones and overlays the service territories of PG&E, SCE and SDG&E.

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[62] See http://www.energy.ca.gov/maps/climate_zone_map.html The California climate zones are not the same as what we commonly call an area like desert or alpine climate. The climate zones are based on energy use, temperature, weather and other factors. Climate zones comprise a geographic area that has similar climatic characteristics.

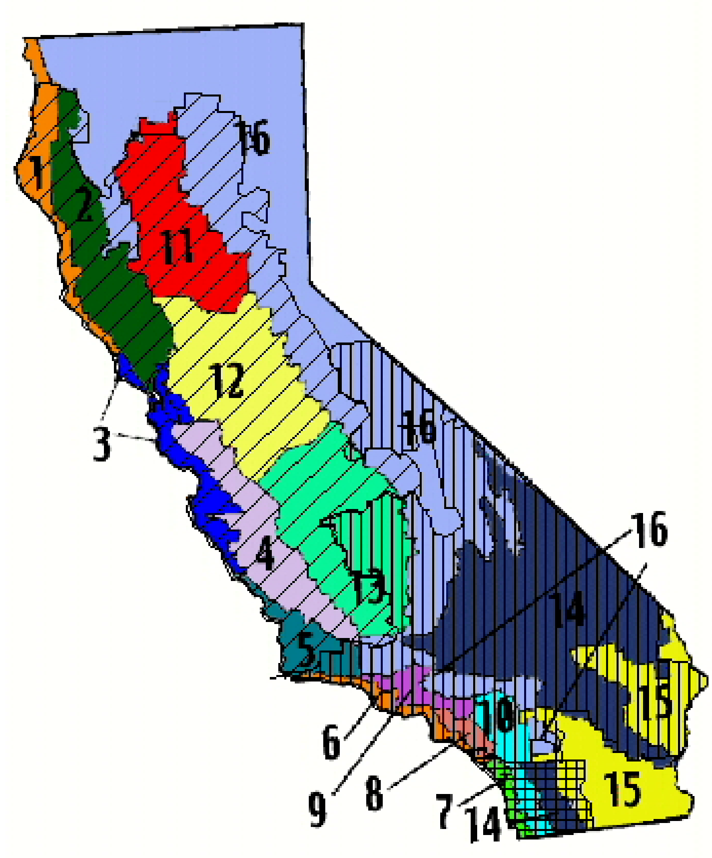

Figure 31: Climate zones per the CEC's Title 24 standards and overlaying service territories.
PG&E (diagonal lines), SCE (vertical lines) and SDG&E (checkered lines) service territories.

E3's gas T&D avoided cost forecasts are differentiated by utility service territory, customer class and season to recognize the time- and area-specific nature of the avoided costs. This report provides gas T&D avoided cost streams for core residential customers, core commercial/industrial customers and total core consumption. The avoided costs of each customer class are further allocated to the winter season (November through March), when the utilities normally experience peak demand.

It is important to note that the avoided T&D costs calculated for this project are designed for evaluating the cost-effectiveness of DSM measures. The costs are not meant to set a precedent for other applications of marginal costs. These results do not preclude a utility from estimating different avoided T&D costs for specific applications. For example, local integrated resource planning studies may require estimation of avoided costs associated with a specific project. The costs estimated herein are area-specific averages, based on all projects and all growth in a given area.

2.5.1 Key Findings and Recommendations

The key findings and recommendations are:

1. Avoided T&D costs are calculated using numerous methods and data sources throughout North America. Within California, the major IOUs have employed no less than five different methods over the past decade.

2. The present worth (PW) approach to calculating avoided costs is the preferred method for capturing the area- and time-specific nature of transmission and distribution avoided costs. Our base case results are calculated using the PW approach. However, the total investment method (TIM) and discounted total investment method (DTIM) yield results comparable to those of the PW method.

3. The replacement cost new (RCN) method is unsuitable for avoided cost calculation because it is based on replacing existing capacity that serves an area's total load, rather than the avoidable capacity expansion intended to serve load growth.

4. The regression methods are unsuitable for DSM cost-effectiveness evaluations because of their reliance on historical data.

5. Electric T&D costs can be allocated to hours based on the relative demand levels in each hour. Barring the availability of hourly load data by climate zone, the CEC's Title 24 Time Dependent Valuation (TDV) research indicates that a reasonable hourly proxy allocation can be developed from hourly temperatures. This report utilizes the same TDV methodology to allocate T&D costs to hours and TOU periods.

6. All three IOUs plan electric transmission avoided costs on a system-wide basis. They vary from a low of $1.16/kW-year in PG&E's service territory to $10.47 and $18.81/kW-year for SDG&E and SCE, respectively. Splitting out transmission avoided costs from distribution allows the CPUC and the utilities to calculate transmission level-only avoided costs for DSM programs at that level.

Annual electric distribution avoided costs by planning area can vary by a factor of seven within a utility. The percentage of those costs that are related to consumption during the summer on-peak time of use (TOU) period can vary by up to 103% by climate zone. However, of the two categories, planning area and climate zone, cluster analysis indicates that climate zone is the dominant avoided cost determinant because planning zones within a climate zone generally have similar avoided costs.[63] Figure 32 displays the weighted average annual T&D avoided costs by climate zone and utility. For climate zones with more than one planning area, the costs are

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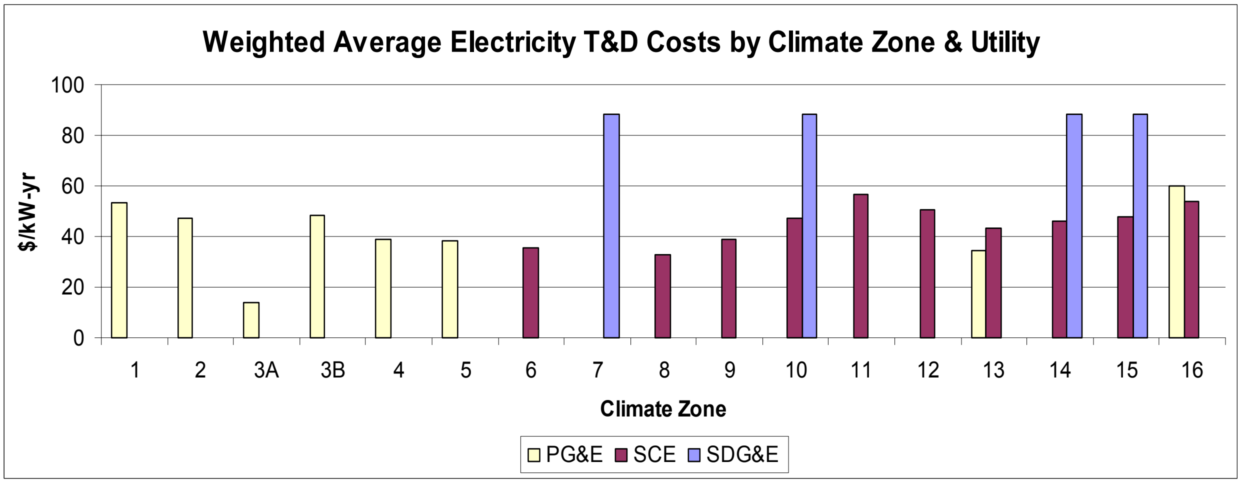
[63] The main exception is Climate Zone Three in the San Francisco Bay Area, which we have divided into 3A and 3B. Climate Zone 3A includes the San Francisco, East Bay and Peninsula sub-areas, while 3B includes portions of Central Coast, Mission and North Bay. The high population density of 3A leads to a significantly lower avoided cost of T&D than for 3B.

weighted by the peak demand in each planning area. Table 13 shows the summer on-peak TOU shares by climate zone.



Note: Climate Zone 3A includes San Francisco, East Bay, and Peninsula sub-areas, while 3B includes portions of Central Coast, Mission, and North Bay.

Figure 32: Electric T&D avoided costs by climate zone.

Table 13: Summer TOU percentages by climate zone and utility

Climate Zone	Utility	Planning Division	Summer On-Peak	Summer Shoulder	Summer Off-Peak
1	PG&E	North Coast	63%	34%	3%
2	PG&E	North Coast, North Bay	93%	2%	5%
3A	PG&E	Peninsula, San Francisco, East Bay	84%	1%	15%
3B	PG&E	Central Coast, North Bay, Mission	84%	1%	15%
4	PG&E	De Anza, San Jose, Los Padres, Central Coast	86%	1%	13%
5	PG&E	Los Padres	61%	19%	20%
6	SCE	Ventura, Dom Hills, Santa Ana	49%	47%	4%
7	SDG&E	SDG&E	67%	7%	26%
8	SCE	Dominguez Hills, Santa Ana	84%	10%	6%
9	SCE	Ventura, Dominguez Hills, Santa Ana, Foothills	83%	5%	12%
10	SCE	Foothills	94%	3%	3%
10	SDG&E	SDG&E	96%	1%	3%
11	PG&E	Sacramento, Sierra, North Valley	73%	2%	24%
12	PG&E	Stockton, Diablo, Mission, Sacramento, Sierra, Yosemite, North Bay	83%	1%	15%
13	PG&E	Kern, Fresno, Yosemite	79%	1%	20%
13	SCE	Ventura	76%	4%	20%
14	SCE	Ventura, Foothills, SCE Rural	47%	41%	12%
14	SDG&E	SDG&E	48%	40%	11%
15	SCE	Foothills, SCE Rural	84%	6%	10%
15	SDG&E	SDG&E	87%	4%	10%
16	PG&E	North Valley, Sierra	75%	2%	22%
16	SCE	SCE Rural	75%	2%	22%

7. Gas T&D avoided costs are less disaggregated than the electric avoided costs. The gas T&D avoided costs presented in this report vary by utility, but not by sub-areas within the utility service territories (see Figure 33). Hourly allocations are not necessary because of the ability of utilities to "pack the pipe" and make use of the natural storage capacity of gas pipelines. Costs are allocated to winter peak months, however, to reflect the winter-peak driven capacity costs (especially for distribution pipe serving core customers).

8. The gas forecast excludes avoided costs for gas storage. This is consistent with Sempra's movement away from considering gas storage as a marginal cost item, and reflects the virtual lack of any storage-related investments in the 2004 forecast provided by PG&E.[64] This result should not prejudice the future inclusion of storage costs. However, in performing future updates, care should be exercised to determine that any storage costs included in the avoided costs are associated with projects that are driven by demand growth (as opposed to reliability needs or procurement cost management).

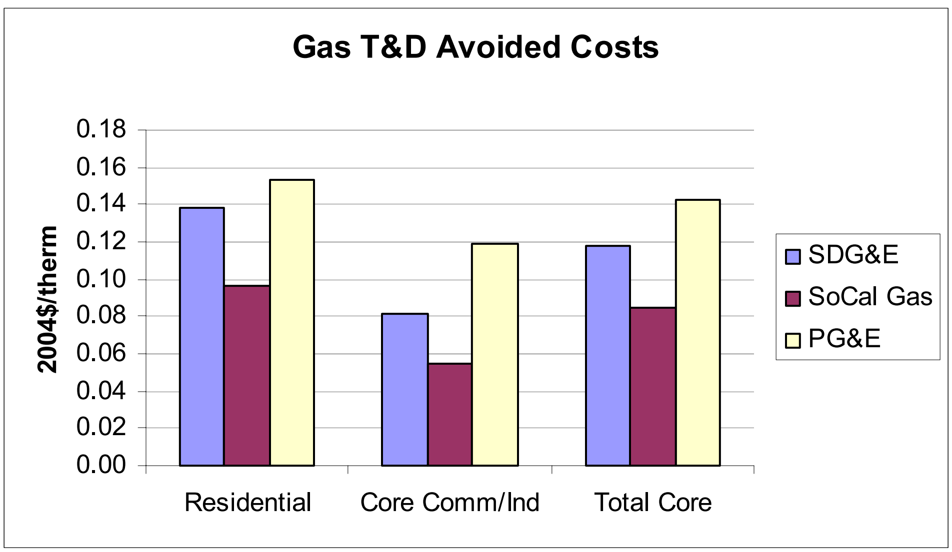


Figure 33: Natural gas T&D avoided costs by utility

9. E3 recommends that the utilities be allowed to de-rate the avoided T&D costs forecast in this report. T&D costs will only be reduced if a significant amount of load reduction is attained in an area, such that the utility expansion plans can be altered. Deration lessens

[64] PG&E's Gas Accord II 2004 capital budget forecasts a total of $2 million for enhanced reliability and capacity of

the problem of "over-valuation" if the utility does not expect to attain enough timely load reduction to affect its construction plans. Deration applies most to the near-term avoided costs, and less to the avoided costs beyond ten or fifteen years.

10. E3 also recommends updating the T&D avoided costs at least once every 3-5 years, in concert with utility rate case cycles. E3 does not expect the update to impose a significant incremental burden on the utilities, although they may need to modify their practices to track planned investments that are driven by peak demand growth, separate from projects to meet other requirements such as reliability, customer connection, and provision of economy energy.

2.5.2 Methodology

Statewide system average Avoided costs of electric and gas transmission and distribution provide a simple way to evaluate the cost-effectiveness of DSM measures. However, marginal demand costs of electricity and gas service vary by area and time.[65] They vary by area because the both the cost and value of distribution capacity within a utility's service territory varies by location.[66]

The time variation arises in two ways. First, avoided costs vary significantly from year to year. The avoided costs are the highest just prior to the construction of a capacity expansion project. However, once the project is built, it would likely be many years before another project is

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storage in 2004.

[65] Woo, CK, B. Horii, D. Lloyd-Zanetti (1997) "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," *IEEE,*PE-493-PWRS-0-12-1997.

[66] Woo, C.K., R. Orans, B. Horii, R. Pupp and G. Heffner (1994) "Area- and Time-specific Marginal Capacity Costs of Electricity Distribution," *Energy: The International Journal*, 19:12, 1213-1218.

required in the area, and the new annual avoided cost for the area would be almost zero.[67] This report used the Present Worth (PW) method to develop avoided cost estimates that capture these area and annual cost differences.

The PW method estimates avoided cost as the opportunity cost of planned capital expenditures from a permanent decrease in load. This avoided cost is reflected in the savings associated with shifting the expansion plan cost stream into the future, often referred to as the deferral value. The PW method yields an avoided cost estimate that varies by planning year, reflecting the greater marginal costs when investment is imminent. An expression of the PW formula is:

$$MC[PW] = \frac{\sum\left[\frac{Invest}{(1+r)^{y}} - \frac{Invest*(1+i)^{\Delta y}}{(1+r)^{y+\Delta y}}\right]}{LoadChange} * AnnualizationFactor$$

where:

Invest = annual demand-related investments in capacity by area ($);
i = escalation rate for the investments;
r = discount rate; y = year;
LoadChange = estimated average change in peak load by area for the planning period;
Δy = deferral caused by load change (annual peak load growth divided by *LoadChange*); and
Annualization Factor = real economic carrying charge for the planning period, grossed up by a variable expense factor.

Avoided T&D costs also vary within the year. For gas T&D, the natural storage capability of the pipeline makes the intra-year variation largely a non-issue, although this report does recognize

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[67] Swisher, Joel and R. Orans (1995) "The Use of Area-Specific Utility Costs to Target Intensive DSM Campaigns,"

that the winter usage drives the pipeline capacity serving core customers. The timing issue, however, is a significant issue for electric T&D. Electric T&D expansion is driven by peak demands. The timing of those peak demands is primarily driven by weather and the types of customers located in the area. Weather is the predominant driver for bulk and local electric transmission system differences, as well as for gas transmission and distribution in California. High temperatures increase the usage of both commercial and residential air conditioning, which is responsible for the majority of peaks in California.

The mix of customer types in an area also influences the peak timing. For example, a highly commercial area will have difference usage patterns and different peak timing than a mostly residential area. Ideally, one would have hourly load profiles for each utility planning area and each climate zone, and allocate the area T&D avoided costs to those hours with the highest likelihood of having the peak demand in any future year. This is the weighted allocation factor that has been used for PG&E and SCE in revenue allocation and rate design proceedings for many years. Unfortunately, that hourly load information does not exist. Absent that information, this report utilizes research performed for the CEC's Title 24 Time-Dependent Valuation (TDV) project that shows that temperature data alone can be used to derive hourly allocation factors for T&D avoided costs.[68] These hourly allocation factors allow the T&D costs to be expressed on an hourly basis by the 16 California Climate Zones, as well as summarized at the TOU level.

Utilities Policy, 5:3/4, 185-197.

[68] Energy and Environmental Economics Inc., Heschong Mahone Group. "Time Dependent Valuation of Energy for Developing Building Energy Efficiency Standards: Time Dependent Valuation 'Cookbook." Submitted to Pacific Gas & Electric (April 12, 2002).

Estimating Electric T&D Avoided Costs

E3's approach to calculating electric T&D avoided costs is illustrated in Figure 34. Overall, E3 has used a four-step method to develop the T&D avoided costs:

1. Estimate the annual electric marginal T&D costs by planning area for PG&E, SCE and SDG&E in $/kW-year using the PW method.

2. Develop 20-year forecasts of annual avoided T&D costs by planning area and climate zone for each utility. Costs past the utility T&D planning horizons are escalated at the rate of inflation.

3. Allocate electric T&D costs to peak hours of the year by climate zone and utility using the TDV methodology.

4. Gross up the electric T&D costs by utility-specific demand loss factors (based on the voltage level of the DSM measure).

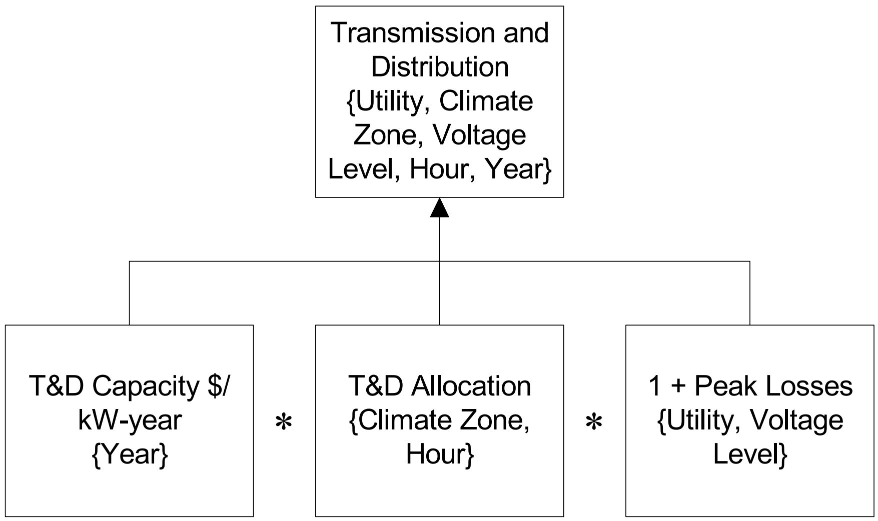

Figure 34: Electric T&D avoided costs methodology

E3 uses the PW method as a uniform approach for all utilities' avoided T&D costs. The PW method provides a theoretically sound estimate of forward-looking avoided costs, and is straightforward to compute.[69] Four other marginal cost estimation methods are currently used by the California utilities. These are shown in Table 14 and are discussed in detail in Appendix C on page 246 of this report.[70]

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[69] See Area-Specific Marginal Costing for Electric Utilities: A case study of Transmission and Distribution Costs, R. Orans, Ph.D. Disseratation, Stanford University, September, 1989.

[70] SDG&E does not calculate marginal electric transmission costs. Rather, the utility uses the embedded cost method and applies directly to the Federal Energy Regulatory Commission (FERC) for cost recovery. SDG&E's gas division and SoCal Gas currently use the regression method to develop marginal costs, but are proposing to switch to an embedded cost approach as well.

Using rate case data provided by the individual utilities, we calculated the future avoided costs of electric T&D using each utility's own approach to calculating marginal costs[71] as well as the PW, TIM, and DTIM methods.[72] E3 found that for each planning area the marginal costs fell within a tight range using the PW, DTIM and TIM methods.[73] Because of the similarity of results, E3 believes that the DTIM or TIM estimates by area would be reasonable substitutes to the PW method, if needed. E3, however, recommends against using the RCN or regression methods for estimating T&D avoided costs for DSM evaluation. Neither of these methods produces reasonably accurate estimates of the future avoided attributable to efficiency programs.

[71] RCN method for SCE, regression method for SDG&E gas and SoCal gas, embedded cost method for SDG&E electric transmission.
[72] Information was not readily available to calculate RCN and regression estimates when those methods were not the utility's preferred method.
[73] We developed a marginal expense factor to ensure that marginal expenses and loaders under the present worth method were consistent with those under the DTIM and TIM methods. The marginal expense factor is calculated as the present value of the marginal expenses (O&M, administrative and general, working capital, etc) over the book life of the asset.

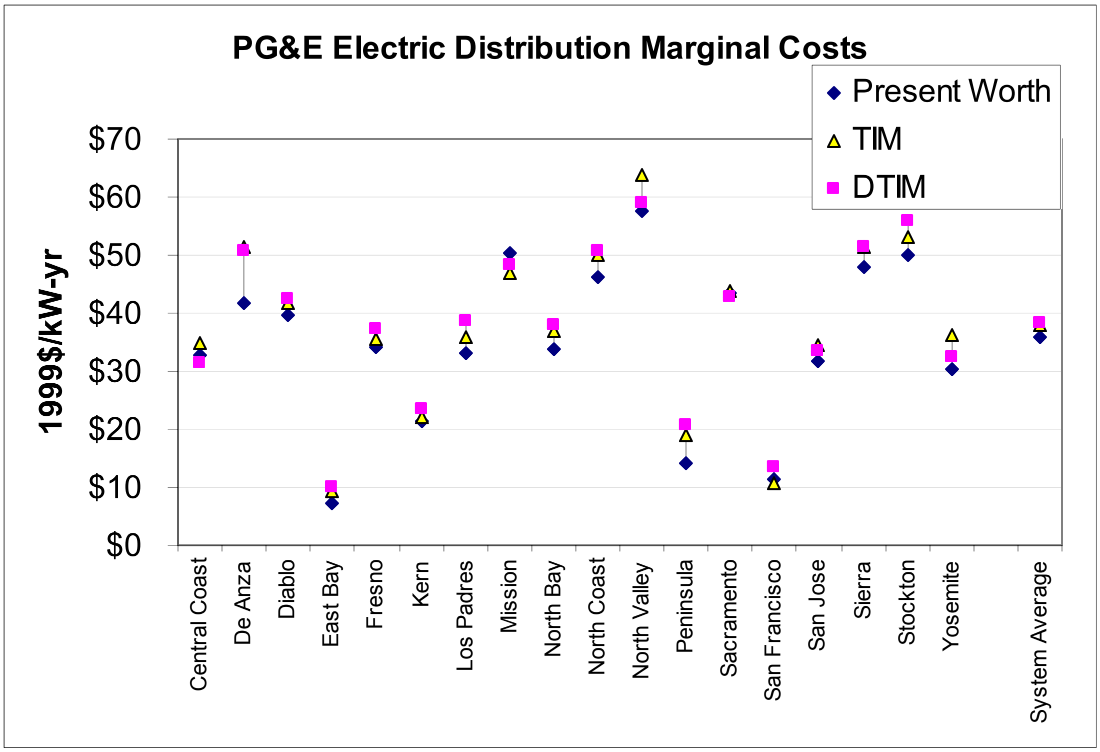
Table 14: Marginal costing methods

Marginal Cost Method	Uses Historic or Forward Looking data	Marginal Cost Basis	Comments	Used by:
Present Worth (PW)	Forward Looking	Value of deferring future investments.	Requires good T&D plans for future investments. Costs are limited to the utility planning horizon.	None today. PG&E in 1993
Discounted Total Investment Method (DTIM)	Forward Looking	Present value of average planned future investment per kW of future growth	Qualities similar to the Present Worth Method	PG&E position since 1996 SDG&E electric distribution
Total Investment Method (TIM)	Forward Looking	Nominal value of average planned future investment per kW of future growth	Qualities similar to the Present Worth Method	PG&E (distribution <$1MM)
Regression Method	Mostly Historic	Slope from an OLS regression of cumulative investment against cumulative load growth.	Office of Ratepayer Advocates proposal. Repudiated by PG&E and the CPUC in 1993, but readopted in 1996.	SDG&E gas SoCal Gas
Replacement Cost New Method (RCN)	Historic Investments, Future Costs	Cost to rebuild the current system. Marginal cost based on "engineering elasticity"*	Does not reflect actual costs	SCE

*Engineering Elasticity is Percentage Change in Cost/Percentage Change in Load from an engineering simulation study.

Figure 35 illustrates the range of electric distribution avoided costs across PG&E's 18 planning areas (divisions). Distribution costs in 1999 ranged from $7.35/kW-year in the East Bay to

$57.74/kW-year in North Valley, using the PW method.[74] Under the DTIM method, the avoided costs of those same areas were $9.84 and $59.05, while under the TIM method they were $9.43 and $63.88, respectively. The differences between the avoided costs are small enough that the methods become interchangeable.



Source: 1999 PG&E General Rate Case filing

Figure 35: PG&E's electric distribution marginal costs by planning division

SCE's service territory shows a similar result. Figure 36 illustrates that SCE's distribution marginal costs generally do not differ greatly for the Ventura, Foothill and Santa Ana

[74] All methods exclude new business primary distribution marginal costs, which are borne by the customer and therefore not avoidable by the utility.

distribution planning areas regardless of whether the PW, DTIM or TIM methods are used. Results under the RCN method diverge significantly where capacity added and load growth in the area are not close.[75] This divergence is one reason that E3 recommends that RCN not be used for DSM evaluation. More importantly, E3 believes that load growth is the appropriate determinant of potential DSM avoided costs, such that the load growth based methods (e.g. PW, DTIM, TIM) are the best available methods to employ in this analysis. Supporting our belief is the fact that reducing load does not cause a utility to replace the existing capacity that serve an area's total load. However, the load reduction, if sufficiently large, can defer a capacity expansion designed to reliably meet the forecast load growth.

[75] This is true for Dominguez Hills and for the rural area. Dominguez Hills has a surplus of distribution capacity relative to load growth for most of the planning horizon, whereas the rural area has a different pattern of capacity costs relative to load growth due to its relatively low population density.

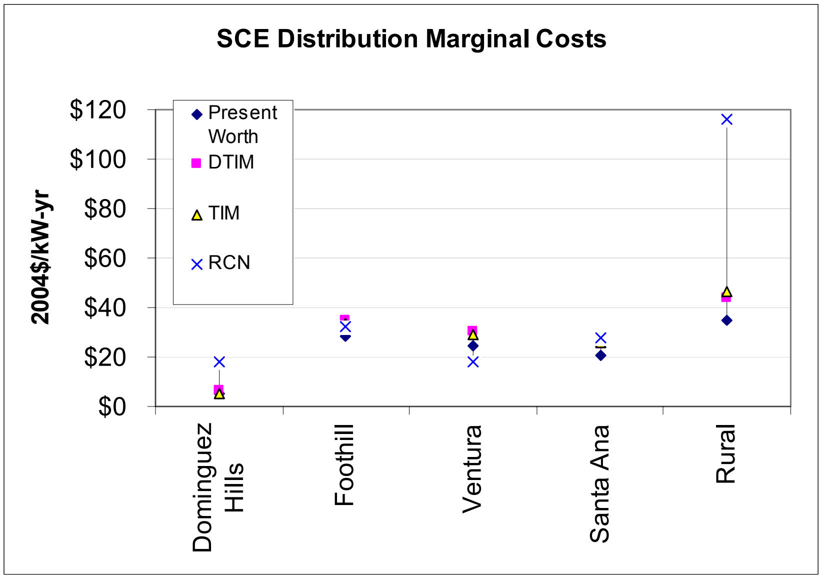


Figure 36: SCE's electric distribution costs by planning area (2003 GRC Ph II)

Given SDG&E's relatively small service territory, SDG&E does not track investments by planning sub-areas in its rate case filings. Figure 37 shows the system-level avoided cost results for distribution under the PW, DTIM, and TIM methods.

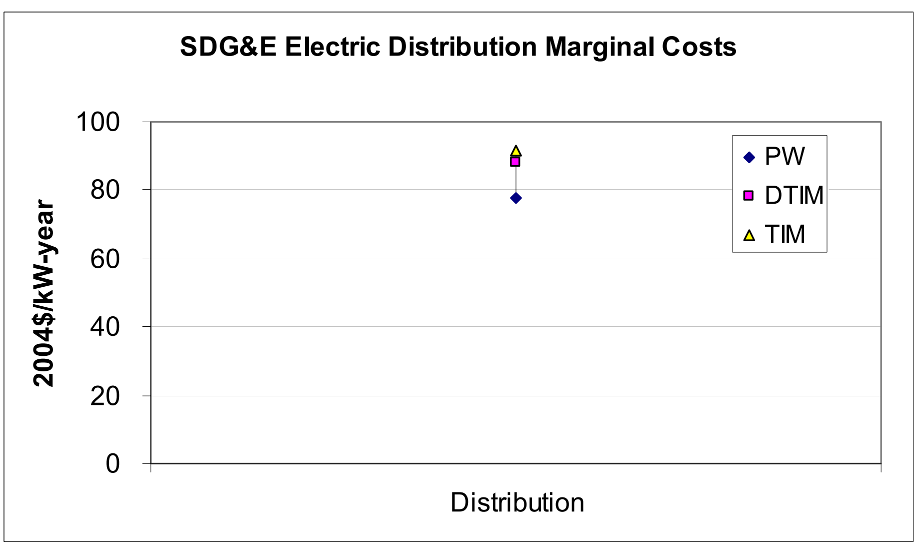


Figure 37: SDG&E's comparative, system-average avoided distribution costs (2004 RDW)

Electric transmission avoided costs, which apply equally across each utility's service territory, varied considerably by IOU, but not by avoided cost method. Figure 38 shows the range of transmission avoided costs for PG&E, SCE and SDG&E using each of the main methods.

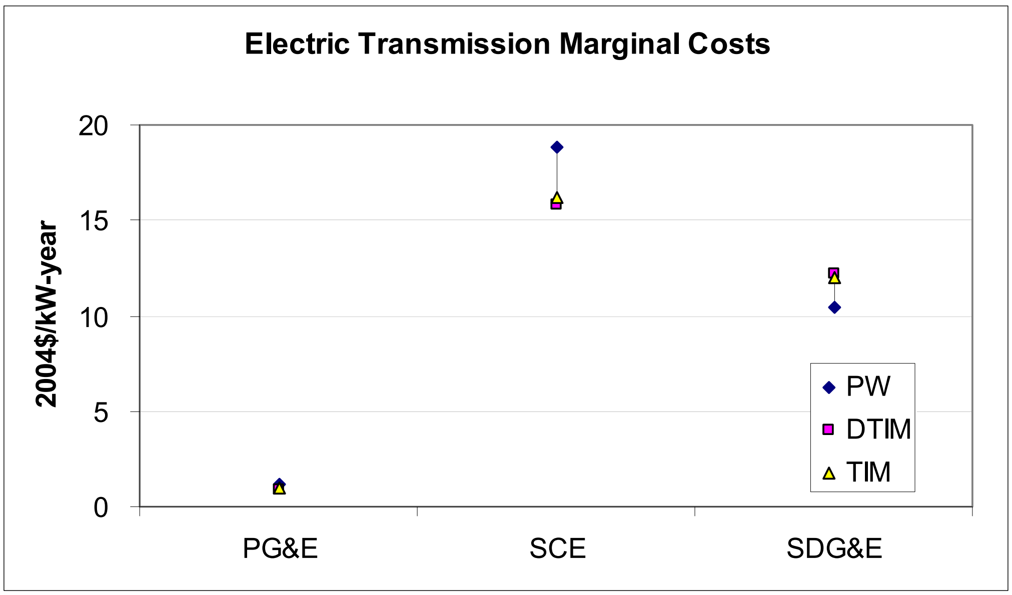


Figure 38: Comparison of electric transmission avoided costs by utility

Forecasting Avoided Costs of Electric T&D

The avoided costs estimates in the prior section were produced using between 5 to 10 years of planning data acquired from utility rate case filings. To extrapolate these estimates into long-term forecasts we escalated the avoided cost estimates at the rate of inflation.

For PG&E and SCE, which have multiple planning areas within their service territories, we also had to determine if and when the area-specific distribution avoided costs should revert to a utility-wide average or continue to escalate at the rates of inflation. Under one scenario, it is reasonable to expect distribution planning areas with high avoided cost areas in the early years of the forecast period to become lower cost areas as the expansion projects are completed. Conversely, areas with initially low avoided costs would become high-cost areas as "surplus" capacity in the areas is "consumed" and distribution capacity expansion becomes imminent.[76] As individual planning areas move through the investment cycle, their long-run average cost could reasonably be expected to converge to the utility's system average.

Under the counter scenario, areas have higher or lower costs because of fundamental differences in the costs to provide capacity in those areas. For example, the amount of underground versus overhead equipment, or the amount of in-fill growth versus green-field growth could significantly affect the avoided costs in the areas. In those cases, the long-run avoided costs should maintain the cost differences and not converse to a system average value.

The forecasts developed in this report present a combination of both scenarios.

San Diego Gas & Electric Company

With just one planning area for distribution and transmission, SDG&E's costs are all utility system averages with different hourly allocations of those costs for each of the four climate

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[76] Swisher, Joel and R. Orans (1995) "The Use of Area-Specific Utility Costs to Target Intensive DSM Campaigns,"

zones in the utility service area. In this case, E3 simply escalated the 2004 avoided costs at the rate of inflation and applied them equally to each of the four climate zones in its service territory. Figure 39 shows the 20-year annual average forecast of SDG&E's T&D avoided costs and compares them to the existing *Policy Manual* T&D values.

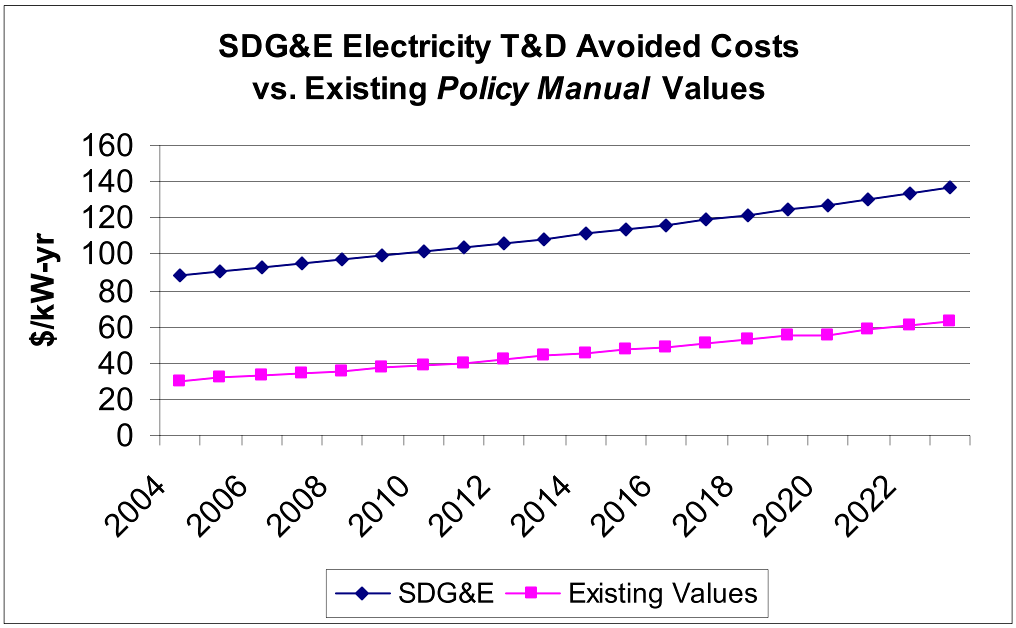


Figure 39: SDG&E's electric T&D avoided costs vs. the 2001 *Policy Manual* values

According to SDG&E, one of the reasons that its costs exceed the current values is the comparatively large amount of undergrounding undertaken by the utility. A second reason is that near-term growth in forecast distribution investments is expected to outstrip load growth, as shown in Figure 40. Whereas incremental load growth is forecast to trend lower between 2003

Utilities Policy, 5:3/4, 189.

and 2007, incremental distribution investments are expected to trend upwards. This has increased the $/kW avoided costs over the planning horizon (2003-2007).

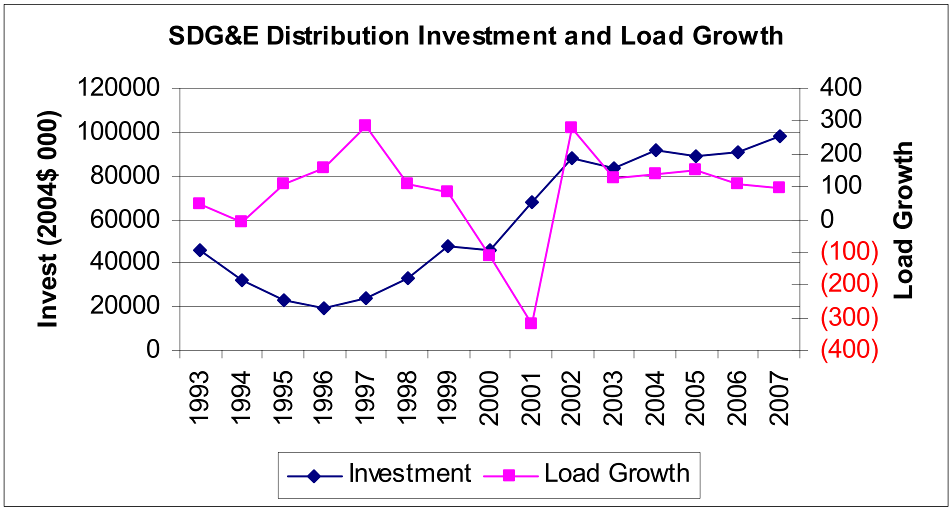


Figure 40: SDG&E's electric distribution investment and load growth

Pacific Gas & Electric Company

PG&E's territory covers 18 planning areas and 9 climate zones (see Figure 41). Given such diversity, the utility indicated to E3 that fundamental differences in population density and climate imply that its area-specific avoided T&D costs should not converge to the system average over the long run. Rather, high density areas with mild temperatures such as San Francisco, the Peninsula and the coastal East Bay will remain low cost due to economies of scale and flatter peak demand. On the other hand, hotter and less populated planning divisions such as North Valley, Stockton and Sacramento will retain relatively high avoided T&D costs.

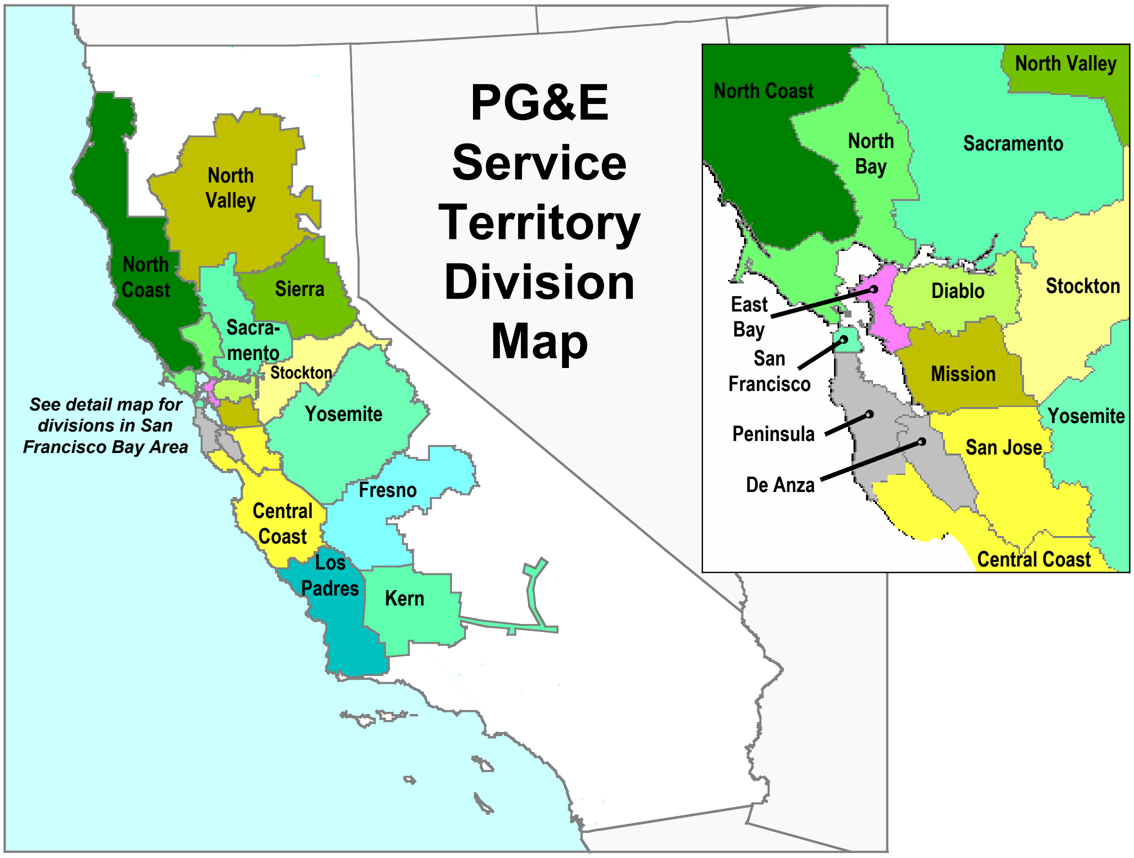


Figure 41: PG&E's distribution planning divisions

Figure 42 shows the selected 20-year annual average avoided cost forecasts for four of PG&E's planning divisions to indicate the range of forecast values, with each of the areas having a separate value stream. The graph also compares PG&E's new avoided costs to the existing statewide electric T&D costs from the *Policy Manual.* PG&E's North Valley and Sacramento areas have significantly higher costs than the existing statewide average and its East Bay and Kern areas have much lower costs than the existing values.

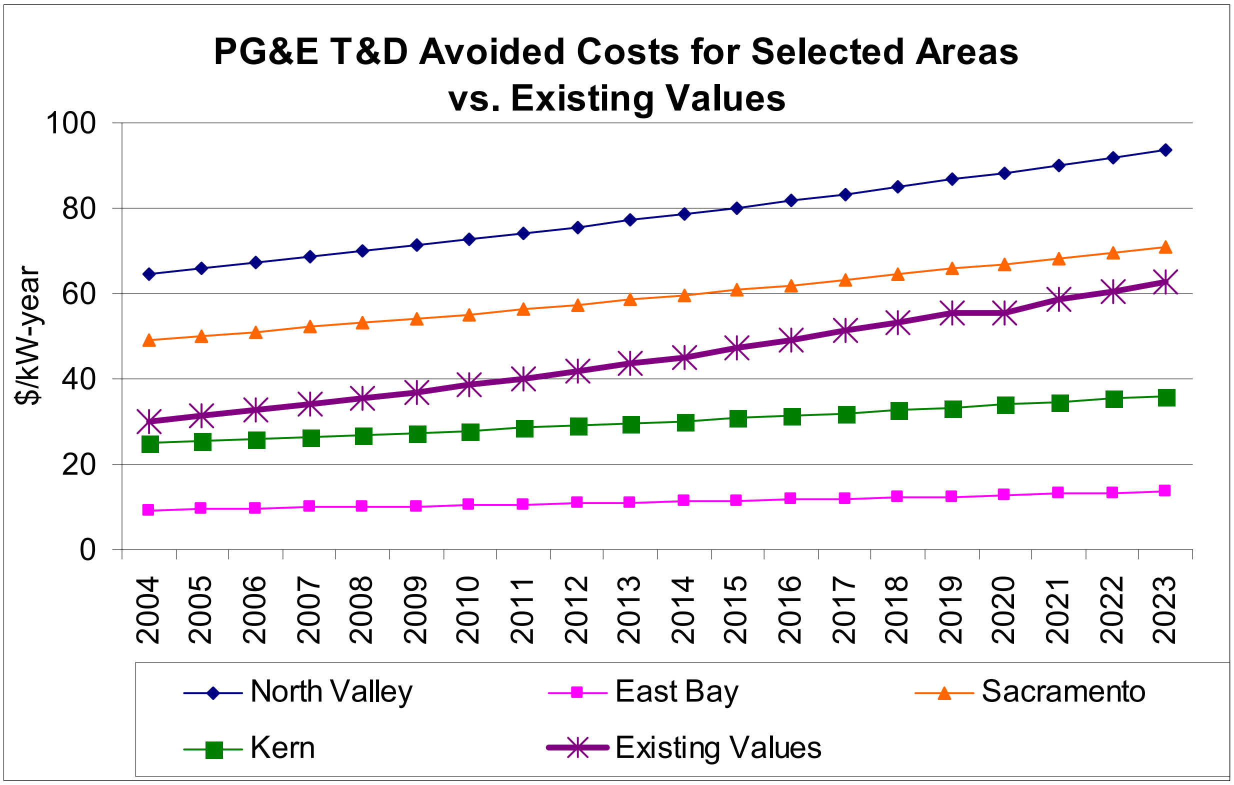


Figure 42: 20-year avoided cost forecasts for 4 of the 18 PG&E planning divisions.

Southern California Edison

Figure 43 illustrates SCE's service territory and planning areas. SCE has 4 distinct planning areas and a 5th extensive *rural* area. SCE expects that the Dominguez Hills, Santa Ana, Foothills and Ventura areas will converge to the system average avoided costs over the long term due to their generally similar characteristics. In addition, these four planning areas overlap many of the same climate zones. However, SCE believed that its large rural area will continue to have higher avoided costs than the other planning areas because it has a comparatively low population density.

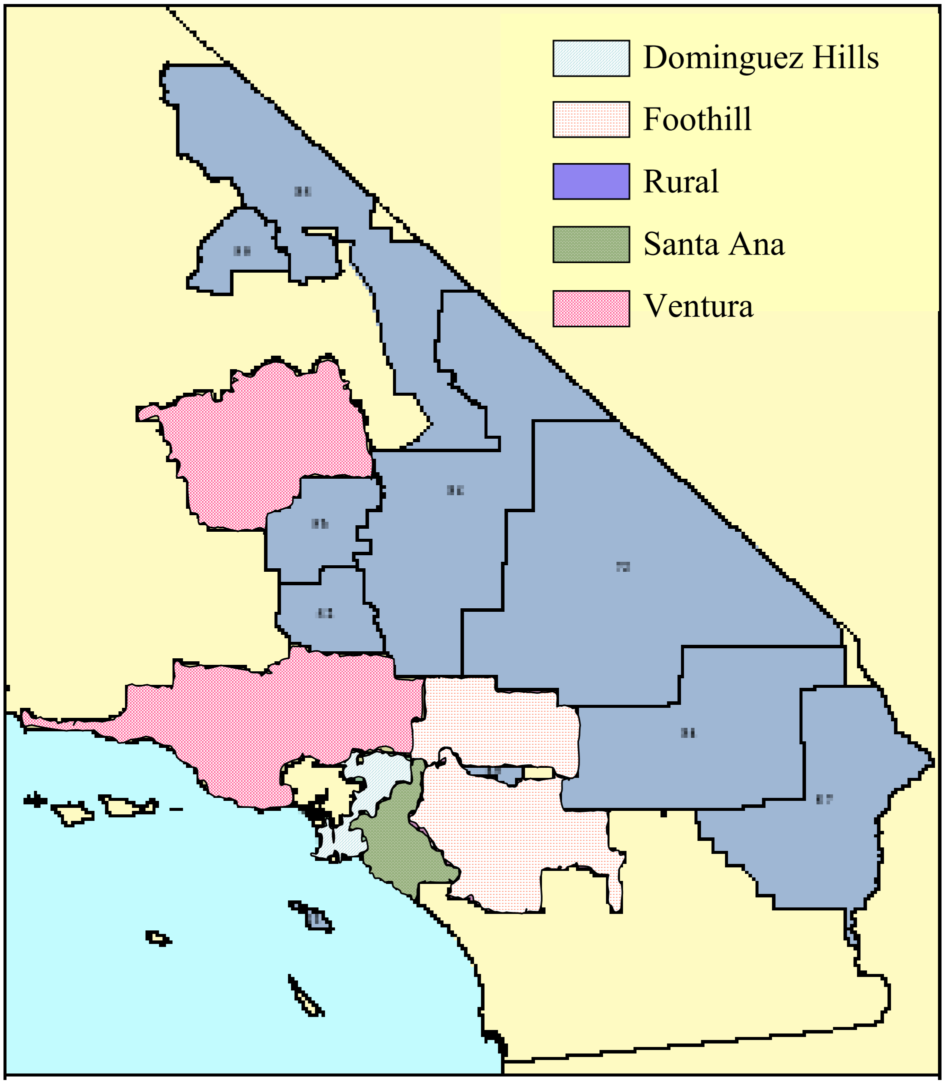


Figure 43: SCE's service territory and planning areas

In Figure 44, we show the avoided T&D costs in each of SCE's 5 planning areas increasing at the rate of inflation through the period covered by SCE's planning horizon (2004-2011). After 2011, we used linear interpolation to transition the four converging areas to the system average over five years. Meanwhile, the rural area avoided costs continue to increase at the rate of inflation. As shown in Figure 44, after 2016, SCE's forecasted avoided T&D costs converge to a single urban system average and rural classification.

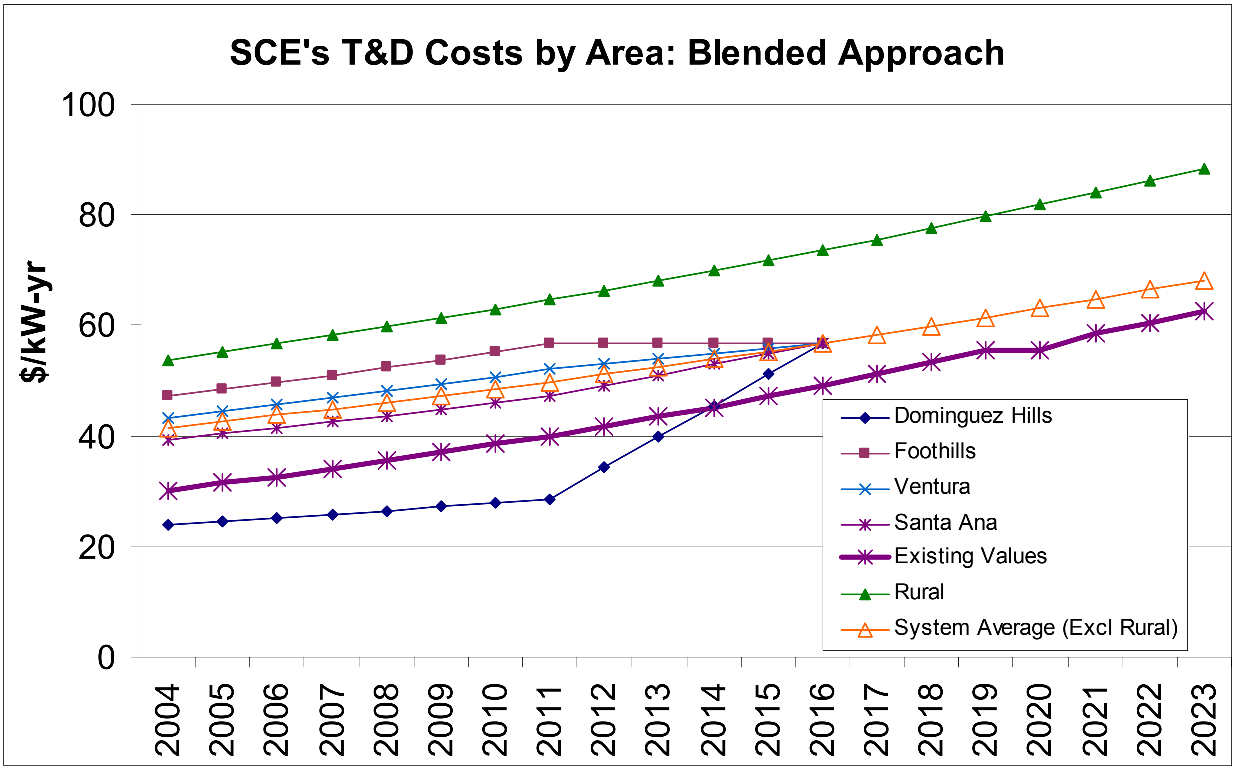


Figure 44: SCE's blended approach to forecasting long-run marginal T&D costs

Allocating Electric T&D Avoided Costs

A fundamental premise of this report is that energy efficiency measure savings should be valued differently at different times to better reflect the actual costs to users, to the utility system, and to society. For example, the savings of an energy measure that is very efficient during hot summer weekday afternoons would be valued more highly than a measure that achieves savings during the off-peak. This reflects the realities of the energy market, where high system demand on summer afternoons drives electricity prices much higher than during, say, nighttime hours in mild weather.

California's electric transmission and distribution systems are built for peak loads on those hot summer days. Therefore, it is important to allocate the T&D marginal costs to the times when those peak loads occur. Since peak loads are largely driven by weather-sensitive end-uses (such as air conditioning), temperature provides a reasonable proxy for peak loads for the purpose of T&D avoided cost allocation.

The time-dependent valuation of energy uses weighed allocation factors as a proxy for peak demand loading on the electric T&D system. This methodology was developed in the CEC's Time Dependent Valuation (TDV) used to develop the new Title 24 building standards that have been recently adopted and will be effective in 2005.

There is a separate weighted allocation factor for each hour of the year and they sum to 1 over the year to create an hourly weight that can be used to allocate the annual average costs to each hour. The 8760 T&D hourly weights are calculated based on the hourly temperature profile for each of the 16 climate zones developed for the CEC's Title 24 building standards using Typical Meteorological Year (TMY) data. Summer peak hours are identified based on hourly temperatures for each climate zone and weights are calculated proportional to how high temperatures are in the summer. Weights are allocated to the hours within 15 degrees of the peak temperature. The highest temperature hour gets the most weight, and the hours with a temperature 15 degrees below peak get the least weight. Hours with temperatures below 15 degrees of the peak temperature do not get any weight. The same allocation rule is used in each climate zone. For example, in the Central Valley there are relatively few hours over the course of the summer during which the temperature escalates to within 15 degrees of the summer peak temperature. In regions like this the temperature can spike dramatically, resulting in high T&D costs because the total costs are spread over a low number of hours. In contrast, in more moderate temperature coastal areas, where there is a lower incidence of spiking temperatures, the same cost allocation methodology results in lower peak period T&D costs as these costs are spread over a significantly greater number of hours.

We used the following method to calculate summer T&D weights:

1. Identify the non-holiday weekdays based on each utility's TOU definitions.

2. Determine the highest temperature of the 8760 TMY data-set occurring on a non-holiday weekday.

3. Identify all non-holiday weekday hours with temperatures within 15 degrees of the maximum, and total the number of occurrences for each full degree "bin."

4. The weighted allocation factor (WAF) for each hour that falls in a bin is determined as follows:

$$WAF\ [\mathrm{h,z}] = \frac{\#\ \mathrm{of\ Hours\ in\ bin\ with\ Temp(h)}}{15}$$

where Temp(h) = Temperature at hour h [Units = deg F]

Although we have developed a similar T&D cost allocation process for the winter peaking planning areas, the areas defined in this project are relatively large and have peak loads during the summer so there was no need to use a winter cost allocation methodology.[77]

Using Climate Zones versus Planning Areas for Weighting Allocated Costs

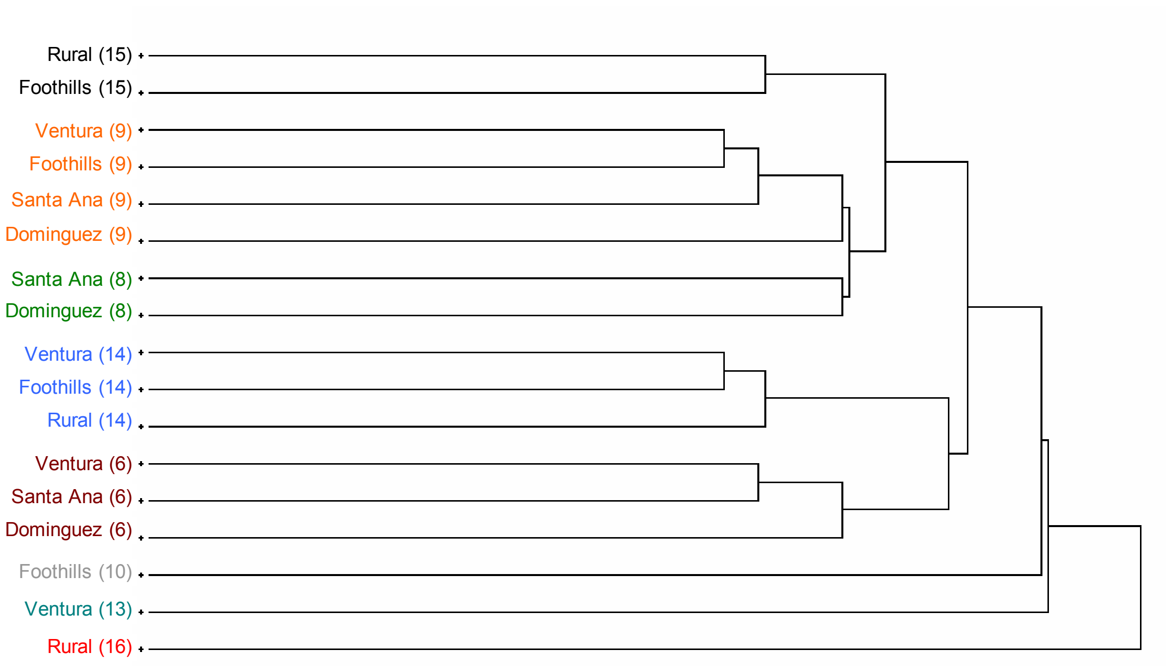
We cross-referenced the utility planning areas to the 16 climate zones that each have a uniquely calculated set of hourly T&D weights to develop the 8760 hourly shapes of T&D avoided costs for each area. Table 15 shows that the time-of-use (TOU) allocations vary considerably by climate zone. In addition, many planning areas cut across several climate zones. Therefore, we calculated both fully disaggregated avoided costs by planning area and weighted average avoided costs by climate zone. Depending on the voltage level of the end-use energy efficiency application, the electric T&D marginal costs are scaled up to include marginal line losses by TOU period at the transmission, primary distribution or secondary distribution level.

[77] Winter peak periods and calculations are analogous to the summer case, but in reverse. The highest weighted allocation factor is assigned to the lowest temperature category, and the weighted allocation factors decline as the temperature increases. Whereas the summer analysis is limited to weekdays, the winter analysis is limited to weekdays between 7am and 9pm. Like the summer analysis, the winter peak period is defined as a 15 degree temperature span. See "Costing Methodology for Electric Distribution System Planning," prepared for *The Energy Foundation by* Energy and Environmental Economics, Inc., Pacific Energy Associates (2000). *See also* "Time Dependent Valuation (TDV) Formulation 'Cookbook'," prepared for Pacific Gas & Electric Company by Energy and Environmental Economics, Inc., Heschong Mahone Group (2002).

Table 15: Utility planning areas mapped to climate zones with TOU %s

Climate Zone	Utility	Planning Division	Summer On-Peak	Summer Shoulder	Summer Off-Peak	Winter On-Peak	Winter Shoulder	Winter Off-Peak
1	PG&E	North Coast	63%	34%	3%	0%	67%	33%
2	PG&E	North Coast, North Bay	93%	2%	5%	0%	53%	47%
3A	PG&E	Peninsula, San Francisco, East Bay	84%	1%	15%	0%	58%	42%
3B	PG&E	Central Coast, North Bay, Mission	84%	1%	15%	0%	58%	42%
4	PG&E	De Anza, San Jose, Los Padres, Central Coast	86%	1%	13%	0%	93%	7%
5	PG&E	Los Padres	61%	19%	20%	0%	40%	60%
6	SCE	Ventura, Dom Hills, Santa Ana	49%	47%	4%	0%	85%	15%
7	SDG&E	SDG&E	67%	7%	26%	57%	0%	43%
8	SCE	Dominguez Hills, Santa Ana	84%	10%	6%	0%	91%	9%
9	SCE	Ventura, Dominguez Hills, Santa Ana, Foothills	83%	5%	12%	0%	87%	13%
10	SCE	Foothills	94%	3%	3%	0%	71%	29%
10	SDG&E	SDG&E	96%	1%	3%	71%	0%	29%
11	PG&E	Sacramento, Sierra, North Valley	73%	2%	24%	0%	86%	14%
12	PG&E	Stockton, Diablo, Mission, Sacramento, Sierra, Yosemite, North Bay	83%	1%	15%	0%	78%	22%
13	PG&E	Kern, Fresno, Yosemite	79%	1%	20%	0%	54%	46%
13	SCE	Ventura	76%	4%	20%	0%	54%	46%
14	SCE	Ventura, Foothills, SCE Rural	47%	41%	12%	0%	96%	4%
14	SDG&E	SDG&E	48%	40%	11%	96%	0%	4%
15	SCE	Foothills, SCE Rural	84%	6%	10%	0%	83%	17%
15	SDG&E	SDG&E	87%	4%	10%	83%	0%	17%
16	PG&E	North Valley, Sierra	75%	2%	22%	0%	85%	15%
16	SCE	SCE Rural	75%	2%	22%	0%	87%	13%

To determine whether marginal costs were more closely grouped by planning areas or climate zones, we conducted a cluster analysis for each utility. The cluster analysis revealed that climate zones dominate the results. Figure 45 below shows a dendrogram for SCE's distribution avoided costs. A dendrogram consists of U-shaped lines connecting objects in a hierarchical tree. The clusters grow in size and decrease in number as we move from left to right in the diagram. The horizontal axis of the tree diagram is a general measure of the similarity of the clusters combined at that point, so branches that join on the left indicate a merging of "more similar" clusters than do branches that join on the right.78 SCE shows that planning areas group together by climate zone. Climate Zone 16 at the bottom of the dendrogram, which represents SCE's rural area, stands on its own. This confirms our approach of maintaining a separate avoided cost value stream for the rural area (known within SCE as "Sector 2"); even as we transition SCE's four other planning areas (known collectively as "Sector 1") to the system average avoided costs beyond the planning horizon. The cluster analysis also shows that if aggregation is desired, it makes more sense to aggregate across planning areas within a climate zone than to aggregate climate zones.



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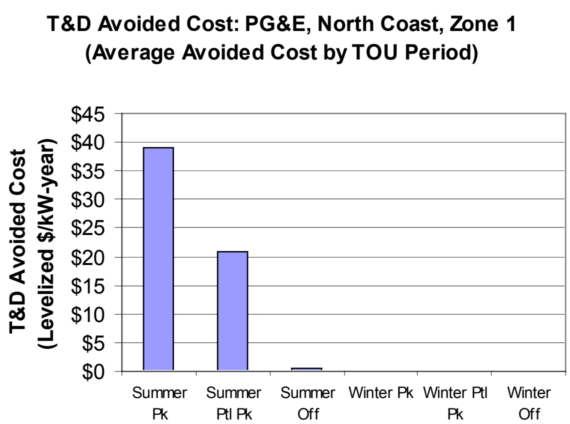
[78] Velleman, Paul F,. *DataDesk Statistics Guide*, Ithaca New York, 1988

Figure 45: Cluster analysis for SCE's distribution avoided costs. Numbers in parentheses refer to climate zones

Figure 46 illustrates the impact of the climate zones on the allocation of the avoided costs to TOU periods. In Climate Zone 1, the relatively mild coastal temperatures in PG&E's North Coast planning division cause the avoided costs to be allocated across a relatively wide band of summer on-peak and shoulder hours. By contrast, in the portion of SDG&E's service territory that overlaps the hot, inland Climate Zone 10, nearly all of the avoided costs are allocated to summer on-peak hours when high temperatures are highest.



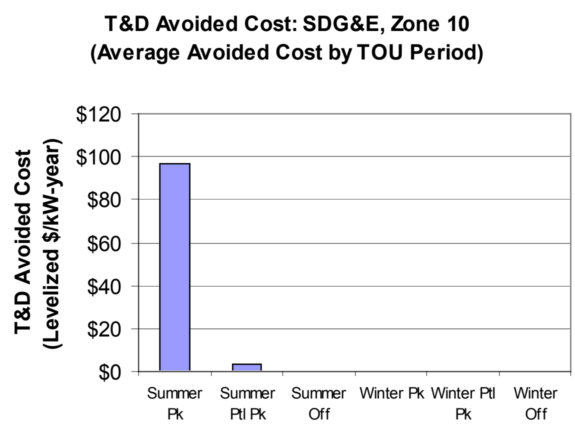


Figure 46: Allocation T&D costs for PG&E's Climate Zone 1 and SDG&E's Climate Zone 10 by TOU Periods

In Figure 47 we display SDG&E's Climate Zone 10 T&D data in a 3-dimensional view as well as a topographic view to illustrate how electric T&D costs can be further disaggregated by hour and month. The figures show that all the avoided costs are allocated to the months of May through September, with the peak occurring in late July and early August around 3 pm on weekdays.

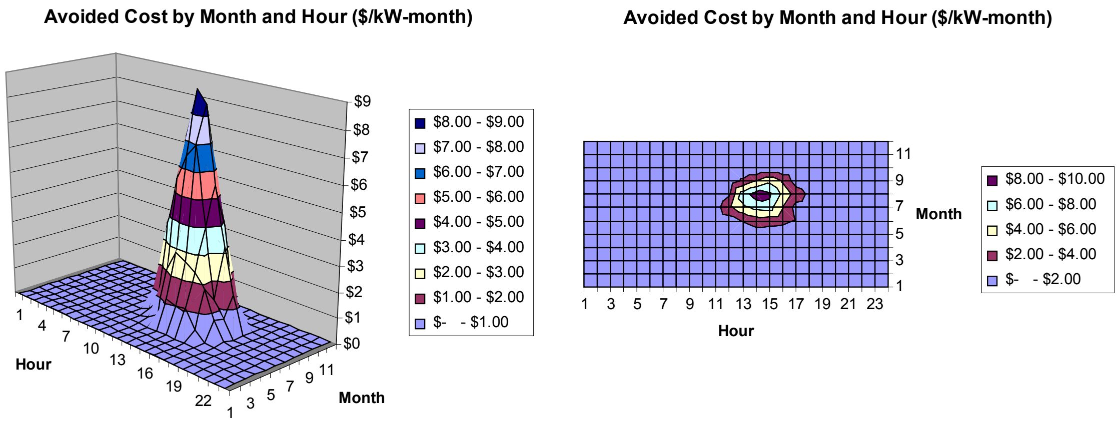


Figure 47: Avoided Electric T&D costs for SDG&E's Climate Zone 10

Estimating Gas T&D Avoided Costs

E3's approach to calculating gas T&D avoided costs is illustrated in Figure 48. At this time, the utilities only track gas T&D marginal investments on a system-wide basis in their regulatory filings. PG&E has indicated that it is considering disaggregating gas local transmission costs to planning areas. However, the processes and computer programs that would be required to support such a filing are not yet in place, and any such filing would not occur for at least two years.

The allocation of gas T&D costs is performed on a seasonal basis. Gas T&D peak demand does not occur on an hourly basis like electricity due to the natural storage capability of the pipelines.

It is more reasonable to allocate the costs to the winter season (November through March), when usage is highest.

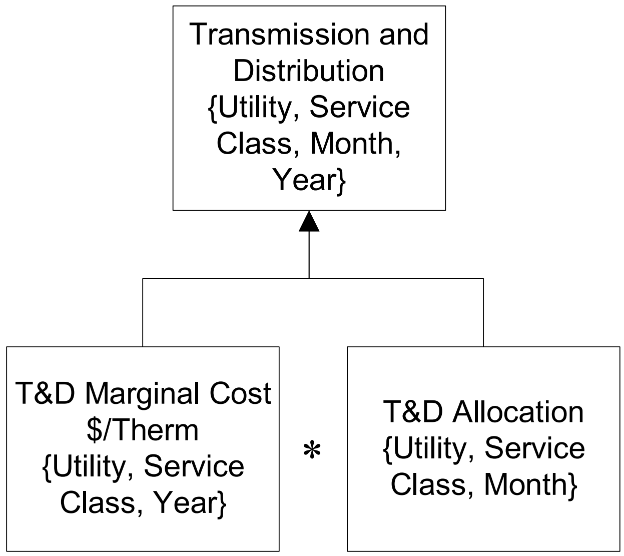


Figure 48: Gas T&D avoided costs

We calculated the results using the present worth method by core customer class (residential and core commercial/industrial) to reflect usage pattern differences. In addition, we have presented the results at the system-average level (total core) in case the utilities believe that to be a more useful indicator. The avoided costs are grossed up for "shrinkage" factors —lost and unaccounted for gas and compression fuel – using multipliers to the gas commodity throughput.

Figure 49 illustrates the range of annual gas distribution avoided costs by core customer class and utility in $/therm. Distribution costs, which account for the majority of gas transportation costs, fall within a relatively narrow range for all three utilities. For simplicity, in the cases of

SDG&E and SoCal Gas, we have added high- and medium-pressure distribution avoided costs together to arrive at total distribution avoided costs.

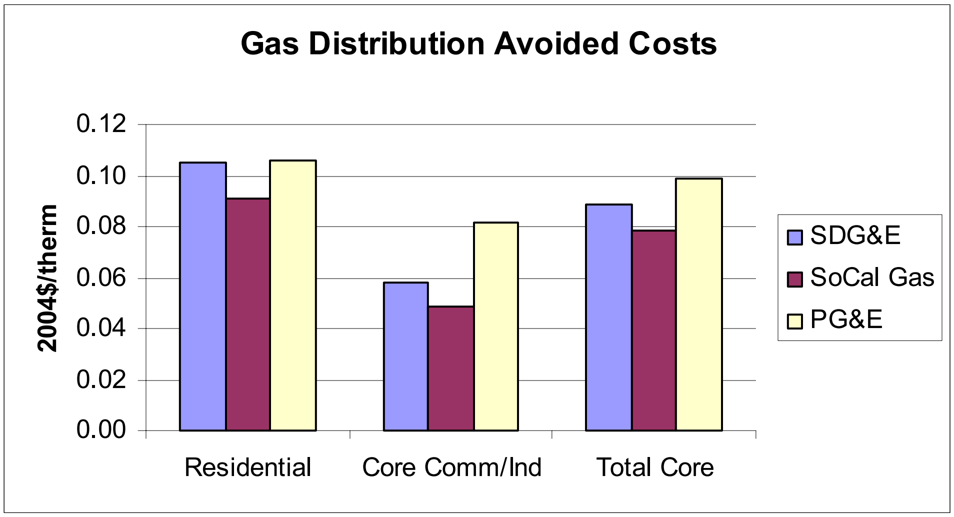


Figure 49: Gas distribution avoided costs

Gas transmission avoided costs are much lower than for distribution due to the infrequency of backbone system expansions. SDG&E's avoided costs over the next 15 years are driven by one $64.9 million pipeline expansion project in 2013 (the Rainbow to Escondido project). SoCal Gas does not foresee any demand-related transmission capacity expansions through at least 2020.[79] Therefore, the avoided costs for SoCal gas transmission in Figure 50 only include marginal operations and maintenance and other expenses. PG&E's gas transmission system includes both backbone transmission and local transmission, which we have grouped together. PG&E's forecast of capital expenditures includes both capacity and new business-related investments, so the marginal costs are "not to exceed" amounts. Finally, PG&E's avoided costs only represent a two-year forecast (2003 and 2004).

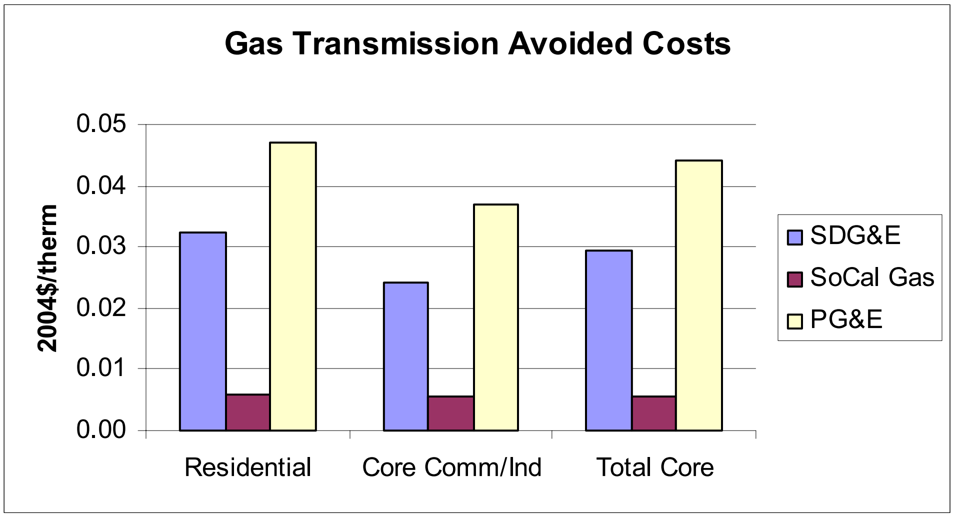


Figure 50: Gas transmission avoided costs by utility

We also considered whether the marginal costs of storage should be included in these forecasts for the purpose of evaluating the cost-effectiveness of DSM programs. Storage is an integral part of the gas T&D system. It allows the utilities to meet peak winter demand levels by making firm withdrawals from gas reserves previously injected into the storage system. As core demand rises, so too does the demand for additional storage capacity. However, core demand is not the only driver of incremental storage investments and may not be the main one. The attractiveness of storage depends on summer/winter price differentials and the national storage market in general. Also, to some extent, storage and backbone transmission are substitutes. SoCal Gas

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[79] *See* "Supplemental Testimony of David M. Bisi" to SoCal Gas' Application 02-12-027 before the CPUC (June 16,

and PG&E both included storage as a marginal cost in their previous Biennial Capacity Allocation Proceedings, but SoCal Gas is now proposing to switch to collecting storage costs for core customers as a non-margin item, as SDG&E already does. PG&E is deferring $22 million of storage expansion projects approved under the Gas Accord II Proposed Decision (11/18/03) and is only planning on investing $2 million in 2004. As such, we are not including storage avoided costs for PG&E at this time. This does not imply, however, that storage costs should not be included for PG&E in the future. As discussed above, however, storage serves functions other than the augmentation of peak capacity. The appropriateness of including storage in a future update would depend upon the extent to which peak capacity requirements are driving the need for the project.

Allocating Gas T&D Avoided Costs

Whereas electricity demand normally peaks during a few high load hours in the summer, gas demand has a smoother shape that rises and falls with the seasons. As such, we have used monthly demand shapes to allocate the avoided costs to the winter season (November through March) when demand is greatest. Figure 51 and Figure 52 illustrate the residential and core commercial/industrial demand curves for each of the utilities. Notice that shapes for commercial and industrial customers are flatter than those for residential customers.

2003).

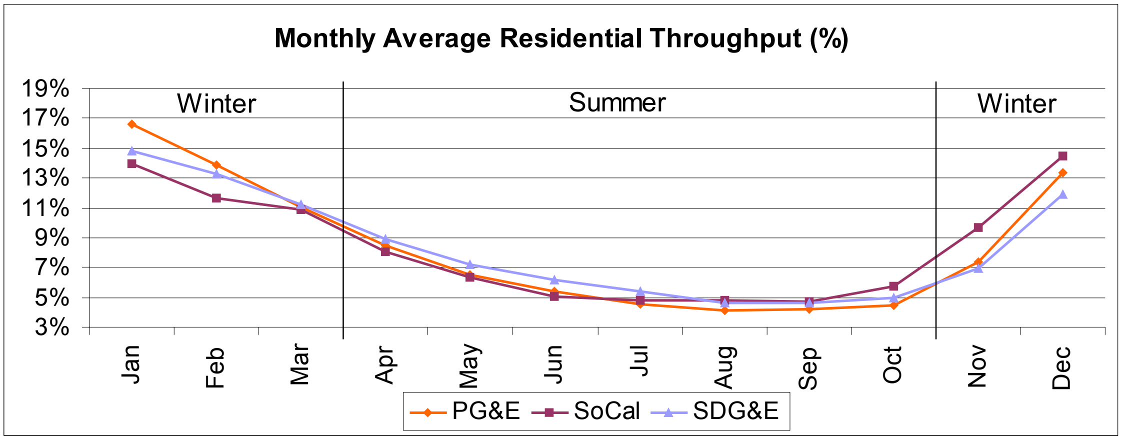

Figure 51: Utility annual gas demand shapes for residential customers

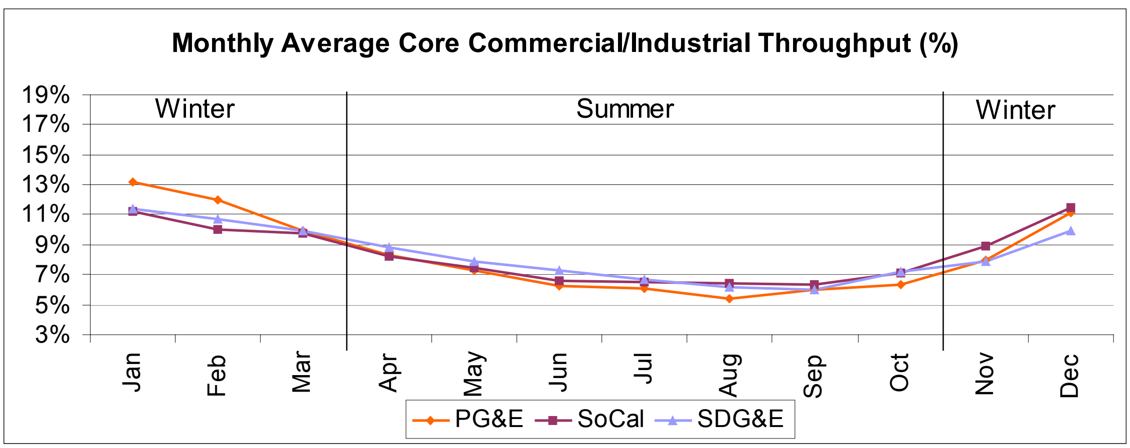

Figure 52: Utility gas demand shape for core commercial/industrial customers

Using these demand curves, we allocated the avoided gas T&D costs by customer class entirely to the winter months. Figure 53 shows how this would look for residential customers in 2004, while Figure 54 and Figure 55 display the allocations for core commercial/industrial and total core, respectively. Finally, utility-specific shrinkage factors are applied to gross up the transported gas commodity for compression fuel and lost and unaccounted for gas.

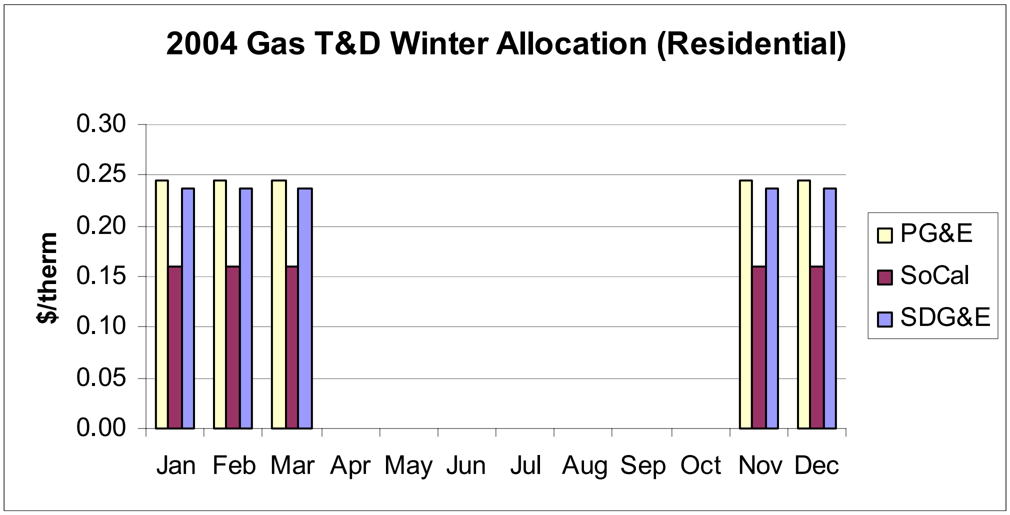

Figure 53: Winter allocation of residential gas T&D avoided costs

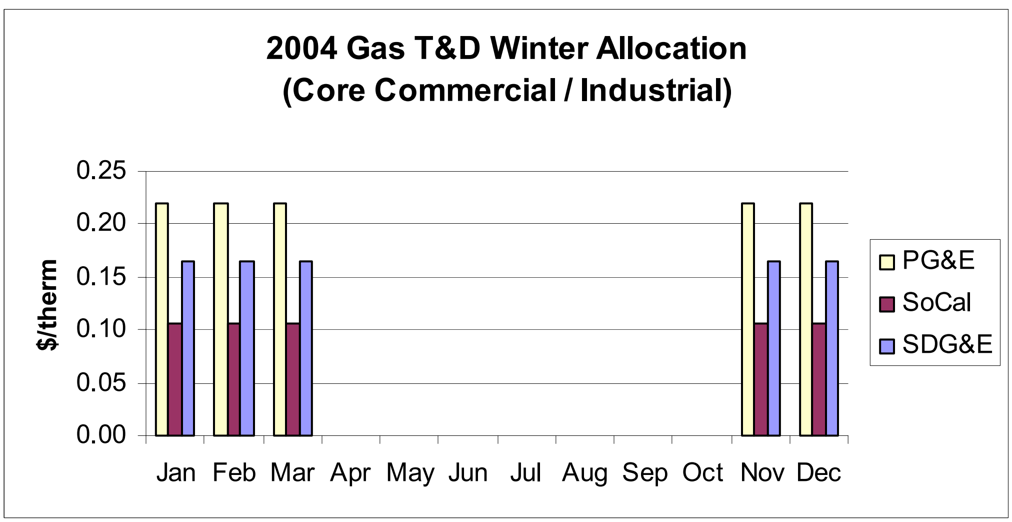

Figure 54: Core commercial/industrial cost allocation by utility

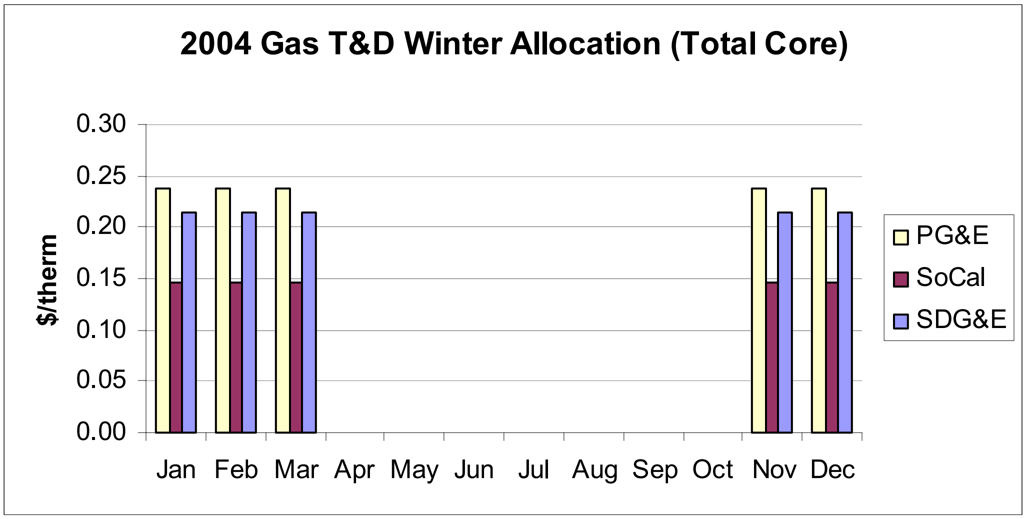

Figure 55: Total core gas T&D allocation by utility

2.5.3 Data Selection

We estimated the electric and gas T&D marginal costs for the California IOUs based on publicly available data from rate cases and supporting workpapers. The data shown in Table 16 through Table 19 is currently available by utility.

Table 16: PG&E Data Sample

Component	Data Description
Electric Distribution	• 1999 GRC filing for 18 divisions (1998-2002). • E3 estimated primary distribution marginal costs (projects > $1MM) using forecast load growth and investments for 1998-2002 • Derived forecast investments for other distribution (projects < $1MM and secondary) based on forecast load growth and 1996-99 marginal investment per kW • Excluded "new business" primary distribution marginal costs, which are borne by the customer
Electric Transmission	• 2003 GRC Phase II filing (data subject to change) • System-average data for 2003-2007
Electric Loss Factors	• 1996 GRC filing
Gas Distribution	• 2004-2007 forecast load and investment data: PG&E gas regulatory group (Jeff Bryant) • Gas throughput forecast from Gas Accord II (2002) • Marginal cost loaders from 2002 GRC: Table 2-13, 2-21 and Applic. Ex. PG&E-6 (Distribution Results of Operation, Ch. 17)
Gas Transmission	• 2003-2004 forecast data: Gas Accord II (Proposed Decision 11/18/03)
Gas Loss and Compression Fuel Factors	• Rule 21: Transportation of Natural Gas: on the Internet at http://www.pge.com/customer_services/business/tariffs/pdf/GR21.pdf

Table 17: SCE Data Sample

Component	Data Description
Electric Distribution	• 2003 GRC Phase II workpapers (2002-2011) for 5 major zones • E3 began analysis in 2003 because load growth negative in 2002 following California electricity crisis
Electric Transmission	• 2003 GRC Phase II workpapers (2002-2006) for 5 zones • 2003: the first year with load growth data • E3 ignored economic projects, which are for reliability
Electric Loss Factors	• 1995 GRC filing

Table 18: SDG&E Data Sample

Component	Data Description
Electric Distribution	• 2004 Rate Design Window (RDW) proceedings (subject to change) • Used five years of projected load and capital additions (2003-2007). Ignored 10 years of historical data.
Electric Transmission	• March 2003 FERC Transmission Tariff Filing (embedded cost approach) • Only two full years of incremental investment data (2002-2003) • SDG&E has clarified which investments are demand-related, but further refinements are possible
Electric Loss Factors	• 2004 RDW filing
Gas Distribution	• Used forecast data (2003-2007) from the 2005 BCAP filing (A.03-09-031)
Gas Transmission	• Used forecast data (2005-2018) from 2005 BCAP filing (A.03-09-031). Excluded 2004 due to forecast decline in incremental throughput
Gas Loss and Compression Factors	• SDG&E analyst (Allison Smith)

Table 19: SoCal Gas Data Sample

Component	Data Description
Gas Distribution	• Used forecast data (2003-2007) from the 2005 BCAP filing (A.03-09-008)
Gas Transmission	• No incremental investment during planning horizon (2004-2018). Only used incremental marginal expenses (O&M, A&G, etc) from 2005 BCAP
Gas Loss and Compression Factors	• SoCal Gas analyst (Allison Smith)

From the available data, we selected our sample using the following criteria: (a) only forecast load and investment data where possible; (b) the most recent data available; (c) only demand growth-related investments; (d) exclude data affected by the California crisis (2000-2002) if it reflects historic values rather than pre-crisis normal expectations.

In practice, these criteria meant that we used PG&E's 1998-2002 electric distribution data even though they overlapped the California electricity crisis because the data were prepared in 1997 and were forward looking. By contrast, we excluded PG&E's monthly gas sales data from January-September 2002 because they were recorded values. Instead, we used the growth rate between those months in the 2003 and 2004 forecasts to back-forecast the January-September 2002 values. We also excluded SCE's electric T&D data before 2003 because they were impacted by the crisis. In the case of SDG&E and SoCal Gas, we excluded the ten years of historical data used in their regression analyses and only considered forecast data.

2.5.4 Results by Location

The following three tables show the 2004 electric avoided cost results by division planning area and by climate zone. We have calculated average avoided costs by climate zone by weighting the individual area marginal costs by their respective peak loads. Since SDG&E has only one planning zone, its avoided costs do not vary by climate zone.

We have developed the results using the greatest amount of disaggregation possible, but the numbers can easily be rolled up into regional values if that is more practical from an implementation perspective.

Table 20: PG&E's electric T&D avoided costs by area and climate zone

PG&E	Climate Zone	T&D 2004$/kW-yr	2002 Peak Load (MW)	Wtd Avg Climate Zone Price
North Coast	1	$51.94	930	$51.94
North Coast	2	$51.94	930	$46.23
North Bay	2	$38.23	664	
East Bay	3	$9.25	769	$13.31
San Francisco	3	$13.54	1,007	
Peninsula	3	$16.78	835	
North Bay	3	$38.23	664	$47.35
Central Coast	3	$37.11	824	
Mission	3	$56.73	1,545	
Los Padres	4	$37.71	516	$38.59
De Anza	4	$47.29	745	
San Jose	4	$35.97	1,833	
Central Coast	4	$37.11	824	
Los Padres	5	$37.71	516	$37.71
Sacramento	11	$49.11	975	$55.13
North Valley	11	$64.76	736	
Sierra	11	$53.89	978	
Diablo	12	$44.82	1,274	$49.62
Mission	12	$56.73	1,545	
Stockton	12	$56.36	1,163	
Sacramento	12	$49.11	975	
Sierra	12	$53.89	978	
Yosemite	12	$34.42	1,076	
Fresno	13	$38.86	1,962	$33.54
Kern	13	$24.84	1,306	
Yosemite	13	$34.42	1,076	
North Valley	16	$64.76	736	$58.55
Sierra	16	$53.89	978	

Table 21: SCE's electric T&D avoided costs by area and climate zone

SCE	Climate Zone	T&D 2004$/kW-yr	2004 Peak Load (MW)	Wtd Avg CZ Price
Ventura	6	$43.31	3,391	$35.66
Dominguez Hills	6	$23.84	3,953	
Santa Ana	6	$39.33	5,669	
Dominguez Hills	8	$23.84	3,953	$32.97
Santa Ana	8	$39.33	5,669	
Ventura	9	$43.31	3,391	$38.98
Dominguez Hills	9	$23.84	3,953	
Santa Ana	9	$39.33	5,669	
Foothills	9	$47.19	5,265	
Foothills	10	$47.19	5,265	$47.19
Ventura	13	$43.31	3,391	$43.31
Ventura	14	$43.31	3,391	$46.04
SCE Rural	14	$53.82	411	
Foothills	14	$47.19	5,265	
Foothills	15	$47.19	5,265	$47.67
SCE Rural	15	$53.82	411	
SCE Rural	16	$53.82	411	$53.82

Table 22: SDG&E's electric T&D avoided costs by area and climate zone

SDG&E	Climate Zone	T&D 2004$/kW-yr	2004 Peak Load (MW)	Wtd Avg CZ Price
SDG&E	7	$88.23	4,026	$88.23
SDG&E	10	$88.23	4,026	$88.23
SDG&E	14	$88.23	4,026	$88.23
SDG&E	15	$88.23	4,026	$88.23

2.5.5 Forecast Values

The next three tables show the 20-year electric distribution avoided cost forecasts in nominal dollars per kW-year by utility, planning area and climate zone. PG&E has a unique forecast for each planning division, reflecting the differences in population density and climate. SCE's Dominguez Hills, Foothills, Santa Ana and Ventura planning areas converge to the system average by 2017, leaving only its rural zone as a separate cost stream. SDG&E has a single stream for all four climate zones.

Table 23: PG&E Forecast Distribution Avoided Costs (2004-2013)

(Nominal $/kW-year)

Planning Area	Climate Zone	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
North Coast	1	$ 50.78	$ 51.78	$ 52.79	$ 53.82	$ 54.87	$ 55.94	$ 57.03	$ 58.14	$ 59.27	$ 60.43
North Coast	2	$ 50.78	$ 51.78	$ 52.79	$ 53.82	$ 54.87	$ 55.94	$ 57.03	$ 58.14	$ 59.27	$ 60.43
North Bay	2	$ 37.08	$ 37.80	$ 38.54	$ 39.29	$ 40.06	$ 40.84	$ 41.63	$ 42.45	$ 43.27	$ 44.12
East Bay	3A	$ 8.09	$ 8.25	$ 8.41	$ 8.58	$ 8.74	$ 8.91	$ 9.09	$ 9.27	$ 9.45	$ 9.63
Peninsula	3A	$ 15.62	$ 15.93	$ 16.24	$ 16.55	$ 16.88	$ 17.21	$ 17.54	$ 17.88	$ 18.23	$ 18.59
San Francisco	3A	$ 12.39	$ 12.63	$ 12.88	$ 13.13	$ 13.38	$ 13.64	$ 13.91	$ 14.18	$ 14.46	$ 14.74
Central Coast	3B	$ 35.95	$ 36.66	$ 37.37	$ 38.10	$ 38.84	$ 39.60	$ 40.37	$ 41.16	$ 41.97	$ 42.78
Mission	3B	$ 55.57	$ 56.66	$ 57.76	$ 58.89	$ 60.04	$ 61.21	$ 62.41	$ 63.62	$ 64.86	$ 66.13
North Bay	3B	$ 37.08	$ 37.80	$ 38.54	$ 39.29	$ 40.06	$ 40.84	$ 41.63	$ 42.45	$ 43.27	$ 44.12
Central Coast	4	$ 35.95	$ 36.66	$ 37.37	$ 38.10	$ 38.84	$ 39.60	$ 40.37	$ 41.16	$ 41.97	$ 42.78
De Anza	4	$ 46.13	$ 47.03	$ 47.95	$ 48.88	$ 49.84	$ 50.81	$ 51.80	$ 52.81	$ 53.84	$ 54.89
Los Padres	4	$ 36.56	$ 37.27	$ 38.00	$ 38.74	$ 39.50	$ 40.27	$ 41.05	$ 41.85	$ 42.67	$ 43.50
San Jose	4	$ 34.81	$ 35.49	$ 36.18	$ 36.89	$ 37.61	$ 38.34	$ 39.09	$ 39.85	$ 40.63	$ 41.42
Los Padres	5	$ 36.56	$ 37.27	$ 38.00	$ 38.74	$ 39.50	$ 40.27	$ 41.05	$ 41.85	$ 42.67	$ 43.50
North Valley	11	$ 63.60	$ 64.84	$ 66.11	$ 67.40	$ 68.71	$ 70.05	$ 71.42	$ 72.81	$ 74.23	$ 75.68
Sacramento	11	$ 47.96	$ 48.89	$ 49.85	$ 50.82	$ 51.81	$ 52.82	$ 53.85	$ 54.90	$ 55.97	$ 57.07
Sierra	11	$ 52.73	$ 53.76	$ 54.81	$ 55.88	$ 56.97	$ 58.08	$ 59.21	$ 60.37	$ 61.55	$ 62.75
Diablo	12	$ 43.67	$ 44.52	$ 45.39	$ 46.27	$ 47.18	$ 48.10	$ 49.04	$ 49.99	$ 50.97	$ 51.96
Mission	12	$ 55.57	$ 56.66	$ 57.76	$ 58.89	$ 60.04	$ 61.21	$ 62.41	$ 63.62	$ 64.86	$ 66.13
North Bay	12	$ 37.08	$ 37.80	$ 38.54	$ 39.29	$ 40.06	$ 40.84	$ 41.63	$ 42.45	$ 43.27	$ 44.12
Sacramento	12	$ 47.96	$ 48.89	$ 49.85	$ 50.82	$ 51.81	$ 52.82	$ 53.85	$ 54.90	$ 55.97	$ 57.07
Sierra	12	$ 52.73	$ 53.76	$ 54.81	$ 55.88	$ 56.97	$ 58.08	$ 59.21	$ 60.37	$ 61.55	$ 62.75
Stockton	12	$ 55.20	$ 56.28	$ 57.38	$ 58.50	$ 59.64	$ 60.80	$ 61.99	$ 63.20	$ 64.43	$ 65.69
Yosemite	12	$ 33.26	$ 33.91	$ 34.57	$ 35.25	$ 35.93	$ 36.63	$ 37.35	$ 38.08	$ 38.82	$ 39.58
Fresno	13	$ 37.71	$ 38.44	$ 39.19	$ 39.96	$ 40.74	$ 41.53	$ 42.34	$ 43.17	$ 44.01	$ 44.87
Kern	13	$ 23.68	$ 24.14	$ 24.61	$ 25.09	$ 25.58	$ 26.08	$ 26.59	$ 27.11	$ 27.64	$ 28.18
Yosemite	13	$ 33.26	$ 33.91	$ 34.57	$ 35.25	$ 35.93	$ 36.63	$ 37.35	$ 38.08	$ 38.82	$ 39.58
North Valley	16	$ 63.60	$ 64.84	$ 66.11	$ 67.40	$ 68.71	$ 70.05	$ 71.42	$ 72.81	$ 74.23	$ 75.68
Sierra	16	$ 52.73	$ 53.76	$ 54.81	$ 55.88	$ 56.97	$ 58.08	$ 59.21	$ 60.37	$ 61.55	$ 62.75

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Table 24: PG&E Electric Distribution Avoided Costs (2014-2023)
(Nominal $/kW-year)

Planning Area	Climate Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
North Coast	1	$ 64.46	$ 65.71	$ 67.00	$ 68.30	$ 69.64	$ 71.00	$ 72.38	$ 73.79	$ 75.23	$ 76.70
North Coast	2	$ 64.46	$ 65.71	$ 67.00	$ 68.30	$ 69.64	$ 71.00	$ 72.38	$ 73.79	$ 75.23	$ 76.70
North Bay	2	$ 47.48	$ 48.40	$ 49.35	$ 50.31	$ 51.29	$ 52.29	$ 53.31	$ 54.35	$ 55.41	$ 56.49
East Bay	3	$ 11.50	$ 11.73	$ 11.96	$ 12.19	$ 12.43	$ 12.67	$ 12.92	$ 13.17	$ 13.42	$ 13.69
San Francisco	3	$ 17.26	$ 17.60	$ 17.94	$ 18.29	$ 18.65	$ 19.01	$ 19.38	$ 19.76	$ 20.15	$ 20.54
Peninsula	3	$ 20.84	$ 21.25	$ 21.66	$ 22.08	$ 22.52	$ 22.95	$ 23.40	$ 23.86	$ 24.32	$ 24.80
North Bay	3	$ 47.48	$ 48.40	$ 49.35	$ 50.31	$ 51.29	$ 52.29	$ 53.31	$ 54.35	$ 55.41	$ 56.49
Central Coast	3	$ 46.27	$ 47.17	$ 48.09	$ 49.03	$ 49.98	$ 50.96	$ 51.95	$ 52.97	$ 54.00	$ 55.05
Mission	3	$ 69.77	$ 71.13	$ 72.52	$ 73.94	$ 75.38	$ 76.85	$ 78.35	$ 79.88	$ 81.44	$ 83.03
Los Padres	3	$ 46.30	$ 47.21	$ 48.13	$ 49.07	$ 50.02	$ 51.00	$ 51.99	$ 53.01	$ 54.04	$ 55.10
Los Padres	4	$ 46.30	$ 47.21	$ 48.13	$ 49.07	$ 50.02	$ 51.00	$ 51.99	$ 53.01	$ 54.04	$ 55.10
De Anza	4	$ 57.93	$ 59.06	$ 60.22	$ 61.39	$ 62.59	$ 63.81	$ 65.06	$ 66.32	$ 67.62	$ 68.94
San Jose	4	$ 43.92	$ 44.78	$ 45.65	$ 46.54	$ 47.45	$ 48.38	$ 49.32	$ 50.28	$ 51.26	$ 52.26
Central Coast	4	$ 46.27	$ 47.17	$ 48.09	$ 49.03	$ 49.98	$ 50.96	$ 51.95	$ 52.97	$ 54.00	$ 55.05
Kern	4	$ 30.81	$ 31.41	$ 32.03	$ 32.65	$ 33.29	$ 33.94	$ 34.60	$ 35.27	$ 35.96	$ 36.66
Los Padres	5	$ 46.30	$ 47.21	$ 48.13	$ 49.07	$ 50.02	$ 51.00	$ 51.99	$ 53.01	$ 54.04	$ 55.10
Sacramento	11	$ 60.99	$ 62.18	$ 63.39	$ 64.63	$ 65.89	$ 67.17	$ 68.48	$ 69.82	$ 71.18	$ 72.57
North Valley	11	$ 80.88	$ 82.46	$ 84.07	$ 85.71	$ 87.38	$ 89.09	$ 90.83	$ 92.60	$ 94.40	$ 96.25
Sierra	11	$ 66.81	$ 68.11	$ 69.44	$ 70.80	$ 72.18	$ 73.59	$ 75.02	$ 76.49	$ 77.98	$ 79.50
Diablo	12	$ 55.23	$ 56.31	$ 57.40	$ 58.52	$ 59.67	$ 60.83	$ 62.02	$ 63.23	$ 64.46	$ 65.72
Mission	12	$ 69.77	$ 71.13	$ 72.52	$ 73.94	$ 75.38	$ 76.85	$ 78.35	$ 79.88	$ 81.44	$ 83.03
Stockton	12	$ 70.42	$ 71.79	$ 73.19	$ 74.62	$ 76.08	$ 77.56	$ 79.08	$ 80.62	$ 82.19	$ 83.80
Sacramento	12	$ 60.99	$ 62.18	$ 63.39	$ 64.63	$ 65.89	$ 67.17	$ 68.48	$ 69.82	$ 71.18	$ 72.57
Sierra	12	$ 66.81	$ 68.11	$ 69.44	$ 70.80	$ 72.18	$ 73.59	$ 75.02	$ 76.49	$ 77.98	$ 79.50
Yosemite	12	$ 42.66	$ 43.50	$ 44.35	$ 45.21	$ 46.09	$ 46.99	$ 47.91	$ 48.84	$ 49.80	$ 50.77
Fresno	13	$ 48.25	$ 49.19	$ 50.15	$ 51.13	$ 52.13	$ 53.14	$ 54.18	$ 55.24	$ 56.32	$ 57.42
Kern	13	$ 30.81	$ 31.41	$ 32.03	$ 32.65	$ 33.29	$ 33.94	$ 34.60	$ 35.27	$ 35.96	$ 36.66
Yosemite	13	$ 42.66	$ 43.50	$ 44.35	$ 45.21	$ 46.09	$ 46.99	$ 47.91	$ 48.84	$ 49.80	$ 50.77
North Valley	16	$ 80.88	$ 82.46	$ 84.07	$ 85.71	$ 87.38	$ 89.09	$ 90.83	$ 92.60	$ 94.40	$ 96.25
North Coast	16	$ 64.46	$ 65.71	$ 67.00	$ 68.30	$ 69.64	$ 71.00	$ 72.38	$ 73.79	$ 75.23	$ 76.70
Sierra	16	$ 66.81	$ 68.11	$ 69.44	$ 70.80	$ 72.18	$ 73.59	$ 75.02	$ 76.49	$ 77.98	$ 79.50
Stockton	16	$ 70.42	$ 71.79	$ 73.19	$ 74.62	$ 76.08	$ 77.56	$ 79.08	$ 80.62	$ 82.19	$ 83.80
Yosemite	16	$ 42.66	$ 43.50	$ 44.35	$ 45.21	$ 46.09	$ 46.99	$ 47.91	$ 48.84	$ 49.80	$ 50.77
Fresno	16	$ 48.25	$ 49.19	$ 50.15	$ 51.13	$ 52.13	$ 53.14	$ 54.18	$ 55.24	$ 56.32	$ 57.42

Table 25: SCE Electric Distribution Avoided Costs (2004-2013)

(Nominal $/kW-year)

Planning Area	Climate Zone	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
Dominguez Hills	6	$ 5.03	$ 5.16	$ 5.30	$ 5.44	$ 5.58	$ 5.73	$ 5.88	$ 6.04	$ 10.35	$ 14.66
Santa Ana	6	$ 20.52	$ 21.07	$ 21.63	$ 22.20	$ 22.79	$ 23.39	$ 24.01	$ 24.65	$ 25.85	$ 27.06
Ventura	6	$ 24.50	$ 25.15	$ 25.82	$ 26.50	$ 27.21	$ 27.93	$ 28.67	$ 29.43	$ 29.84	$ 30.25
Dominguez Hills	8	$ 5.03	$ 5.16	$ 5.30	$ 5.44	$ 5.58	$ 5.73	$ 5.88	$ 6.04	$ 10.35	$ 14.66
Santa Ana	8	$ 20.52	$ 21.07	$ 21.63	$ 22.20	$ 22.79	$ 23.39	$ 24.01	$ 24.65	$ 25.85	$ 27.06
Dominguez Hills	9	$ 5.03	$ 5.16	$ 5.30	$ 5.44	$ 5.58	$ 5.73	$ 5.88	$ 6.04	$ 10.35	$ 14.66
Foothills	9	$ 28.38	$ 29.13	$ 29.90	$ 30.70	$ 31.51	$ 32.34	$ 33.20	$ 34.08	$ 33.72	$ 33.35
Santa Ana	9	$ 20.52	$ 21.07	$ 21.63	$ 22.20	$ 22.79	$ 23.39	$ 24.01	$ 24.65	$ 25.85	$ 27.06
Ventura	9	$ 24.50	$ 25.15	$ 25.82	$ 26.50	$ 27.21	$ 27.93	$ 28.67	$ 29.43	$ 29.84	$ 30.25
Foothills	10	$ 28.38	$ 29.13	$ 29.90	$ 30.70	$ 31.51	$ 32.34	$ 33.20	$ 34.08	$ 33.72	$ 33.35
Ventura	13	$ 24.50	$ 25.15	$ 25.82	$ 26.50	$ 27.21	$ 27.93	$ 28.67	$ 29.43	$ 29.84	$ 30.25
Foothills	14	$ 28.38	$ 29.13	$ 29.90	$ 30.70	$ 31.51	$ 32.34	$ 33.20	$ 34.08	$ 33.72	$ 33.35
SCE Rural	14	$ 35.01	$ 35.94	$ 36.89	$ 37.87	$ 38.87	$ 39.90	$ 40.96	$ 42.04	$ 43.16	$ 44.30
Ventura	14	$ 24.50	$ 25.15	$ 25.82	$ 26.50	$ 27.21	$ 27.93	$ 28.67	$ 29.43	$ 29.84	$ 30.25
Foothills	15	$ 28.38	$ 29.13	$ 29.90	$ 30.70	$ 31.51	$ 32.34	$ 33.20	$ 34.08	$ 33.72	$ 33.35
SCE Rural	15	$ 35.01	$ 35.94	$ 36.89	$ 37.87	$ 38.87	$ 39.90	$ 40.96	$ 42.04	$ 43.16	$ 44.30
SCE Rural	16	$ 35.01	$ 35.94	$ 36.89	$ 37.87	$ 38.87	$ 39.90	$ 40.96	$ 42.04	$ 43.16	$ 44.30

Table 26: SCE Electric Distribution Costs (2014-2023)
(Nominal $/kW-year)

Planning Area	Climate Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
Dominguez Hills	6	$ 18.96	$ 23.27	$ 27.58	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Santa Ana	6	$ 28.27	$ 29.47	$ 30.68	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Ventura	6	$ 30.66	$ 31.07	$ 31.48	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Dominguez Hills	8	$ 18.96	$ 23.27	$ 27.58	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Santa Ana	8	$ 28.27	$ 29.47	$ 30.68	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Dominguez Hills	9	$ 18.96	$ 23.27	$ 27.58	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Foothills	9	$ 32.98	$ 32.62	$ 32.25	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Santa Ana	9	$ 28.27	$ 29.47	$ 30.68	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Ventura	9	$ 30.66	$ 31.07	$ 31.48	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Foothills	10	$ 32.98	$ 32.62	$ 32.25	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Ventura	13	$ 30.66	$ 31.07	$ 31.48	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Foothills	14	$ 32.98	$ 32.62	$ 32.25	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
SCE Rural	14	$ 45.47	$ 46.68	$ 47.91	$ 49.18	$ 50.49	$ 51.83	$ 53.20	$ 54.61	$ 56.06	$ 57.54
Ventura	14	$ 30.66	$ 31.07	$ 31.48	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
Foothills	15	$ 32.98	$ 32.62	$ 32.25	$ 31.89	$ 32.73	$ 33.60	$ 34.49	$ 35.40	$ 36.34	$ 37.30
SCE Rural	15	$ 45.47	$ 46.68	$ 47.91	$ 49.18	$ 50.49	$ 51.83	$ 53.20	$ 54.61	$ 56.06	$ 57.54
SCE Rural	16	$ 45.47	$ 46.68	$ 47.91	$ 49.18	$ 50.49	$ 51.83	$ 53.20	$ 54.61	$ 56.06	$ 57.54

Table 27: SDG&E Electric Distribution Avoided Costs (2004-2013)

(Nominal $/kW-year)

Planning Area	Climate Zone	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
SDG&E	7	$ 77.76	$ 79.56	$ 81.41	$ 83.30	$ 85.23	$ 87.21	$ 89.23	$ 91.30	$ 93.42	$ 95.59
SDG&E	10	$ 77.76	$ 79.56	$ 81.41	$ 83.30	$ 85.23	$ 87.21	$ 89.23	$ 91.30	$ 93.42	$ 95.59
SDG&E	14	$ 77.76	$ 79.56	$ 81.41	$ 83.30	$ 85.23	$ 87.21	$ 89.23	$ 91.30	$ 93.42	$ 95.59
SDG&E	15	$ 77.76	$ 79.56	$ 81.41	$ 83.30	$ 85.23	$ 87.21	$ 89.23	$ 91.30	$ 93.42	$ 95.59

Table 28: SDG&E Electric Distribution Avoided Costs (2014-2023)

(Nominal $/kW-year)

Planning Area	Climate Zone	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
SDG&E	7	$ 97.80	$ 100.07	$ 102.39	$ 104.77	$ 107.20	$ 109.69	$ 112.23	$ 114.84	$ 117.50	$ 120.23
SDG&E	10	$ 97.80	$ 100.07	$ 102.39	$ 104.77	$ 107.20	$ 109.69	$ 112.23	$ 114.84	$ 117.50	$ 120.23
SDG&E	14	$ 97.80	$ 100.07	$ 102.39	$ 104.77	$ 107.20	$ 109.69	$ 112.23	$ 114.84	$ 117.50	$ 120.23
SDG&E	15	$ 97.80	$ 100.07	$ 102.39	$ 104.77	$ 107.20	$ 109.69	$ 112.23	$ 114.84	$ 117.50	$ 120.23

The next two tables show the 20-year forecast of system-wide electric transmission avoided costs for PG&E, SCE and SDG&E.

Table 29: Electric Transmission Avoided Costs (2004-2013)

(Nominal $/kW-yr)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
PG&E	1.16	1.18	1.21	1.24	1.27	1.30	1.33	1.37	1.40	1.43
SCE	18.81	19.31	19.82	20.34	20.88	21.44	22.01	22.59	23.19	23.80
SDG&E	10.47	10.71	10.96	11.21	11.47	11.74	12.01	12.29	12.58	12.87

Table 30: Electric Transmission Avoided Costs (2014-2023)

(Nominal $/kW-yr)

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
PG&E	1.47	1.50	1.54	1.57	1.61	1.65	1.69	1.73	1.77	1.82
SCE	24.43	25.08	25.74	26.43	27.13	27.85	28.58	29.34	30.12	30.92
SDG&E	13.17	13.47	13.78	14.10	14.43	14.77	15.11	15.46	15.82	16.18

The next two tables show the 20-year forecast of gas T&D avoided costs by utility and customer class.

Table 31: Gas T&D avoided costs (2004-2013)

	($/therm)	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
PG&E	*Residential*	0.153	0.156	0.160	0.163	0.167	0.171	0.174	0.178	0.182	0.186
	Core Comm/Ind	0.119	0.121	0.124	0.127	0.130	0.132	0.135	0.138	0.141	0.144
	Total Core	0.143	0.146	0.149	0.152	0.156	0.159	0.162	0.166	0.170	0.173
SoCal Gas	*Residential*	0.097	0.099	0.101	0.103	0.105	0.107	0.110	0.112	0.114	0.117
	Core Comm/Ind	0.054	0.056	0.057	0.058	0.059	0.060	0.062	0.063	0.064	0.066
	Total Core	0.085	0.086	0.088	0.090	0.092	0.094	0.096	0.098	0.100	0.102
SDG&E	*Residential*	0.138	0.141	0.144	0.148	0.151	0.155	0.158	0.162	0.166	0.170
	Core Comm/Ind	0.082	0.084	0.086	0.088	0.090	0.092	0.094	0.097	0.099	0.101
	Total Core	0.118	0.121	0.124	0.127	0.130	0.133	0.136	0.139	0.142	0.146

Table 32: Gas T&D avoided costs (2014-2023)

	($/therm)	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023
PG&E	*Residential*	0.190	0.194	0.199	0.203	0.207	0.212	0.217	0.221	0.226	0.231
	Core Comm/Ind	0.148	0.151	0.154	0.158	0.161	0.165	0.168	0.172	0.176	0.180
	Total Core	0.177	0.181	0.185	0.189	0.193	0.198	0.202	0.206	0.211	0.216
SoCal Gas	*Residential*	0.119	0.122	0.124	0.127	0.130	0.132	0.135	0.138	0.141	0.144
	Core Comm/Ind	0.067	0.069	0.070	0.071	0.073	0.075	0.076	0.078	0.079	0.081
	Total Core	0.104	0.107	0.109	0.111	0.113	0.116	0.118	0.121	0.123	0.126
SDG&E	*Residential*	0.174	0.178	0.182	0.187	0.191	0.195	0.200	0.205	0.210	0.215
	Core Comm/Ind	0.104	0.106	0.109	0.111	0.114	0.117	0.119	0.122	0.125	0.128
	Total Core	0.149	0.153	0.156	0.160	0.164	0.168	0.172	0.176	0.180	0.184

2.6 Reliability Adder

This section describes the methodology used to develop the reliability adder. As specified in the RFP the contractor is to "Develop annual, California specific, dollars/kWh and values for the years 2004-2023, for the reliability value of electricity and natural gas demand reduction." For the purpose of this report, we have placed reliability benefits into two categories:

1. Benefits that accrue under normal conditions. These comprise reduced purchases of ancillary services by the California Independent System Operator (CAISO). This section describes the methodology for estimating avoided ancillary service costs.

2. Benefits that accrue only under low probability scenarios. These are primarily reduced exposure to volatile market prices in the years before California reaches resource balance. We describe the methodology for calculating these benefits in Section 4.0.

2.6.1 Background

California ISO Ancillary Service Definitions

Ancillary services are capacity services in addition to energy that are necessary to ensure reliable grid operations. Ancillary services are generally provided by resources that stand ready to be dispatched at a moment's notice in response to grid operator instructions.

However, some ancillary services can be provided by loads or system control devices. The CAISO procures five ancillary service products through its day-ahead and hour-ahead markets, and two services through long-term contracts. CAISO ancillary services procured hourly are as follows[80]:

- **Regulation Up** and **Regulation Down**: "The service provided either by Generating Units certified by the ISO as equipped and capable of responding to the ISO's direct digital control signals, or by System Resources that have been certified by the ISO as capable of delivering such service to the ISO Control Area, in an upward and downward direction to match, on a real time basis, Demand and resources, consistent with established NERC and WSCC operating criteria. … Regulation includes both the increase of output by a Generating Unit or System Resource ("Regulation Up") and the decrease in output by a Generating Unit or System Resource ("Regulation Down"). Regulation Up and Regulation Down are distinct capacity products, with separately stated requirements and Market Clearing Prices in each Settlement Period."

- **Operating Reserves, Spinning** and **Operating Reserves, Non-Spinning.** Operating Reserves are defined as "the combination of spinning and non-spinning reserve required to meet SWCC and NERC requirements for reliable operation of the grid." Spinning Reserves refers to "the portion of unloaded synchronized generating capacity, controlled by the ISO, which is capable of being loaded in 10 minutes, and which is capable of running for at least two hours." Non-Spinning Reserves refers to "The portion of off-line generating capacity that is capable of being synchronized and ramping to a specified load in ten minutes (or load that is capable of being interrupted in ten minutes) and that is capable of running (or being interrupted) for at least two hours."

- **Replacement Reserves**: "Generating capacity that is dedicated to the ISO, capable of starting up if not already operating, being synchronized to the ISO Controlled Grid, and ramping to a specified Load point within a sixty (60) minute period, the output of which can be continuously maintained for a two hour period. Also, Curtailable Demand that is capable of being curtailed within sixty minutes and that can remain curtailed for two hours.

[80] Ancillary Service definitions can be found in the CAISO tariff, http://www.caiso.com/docs/09003a6080/27/ff/09003a608027ff02.pdf

The CAISO calculates hourly clearing prices for each of these five ancillary services. Suppliers of ancillary services receive the clearing price times the quantity of each service provided, while buyers, including the California IOUs, pay the clearing price times the quantity of each service needed. Ancillary services can also be self-provided, allowing buyers to circumvent the daily ISO auction. Approximately 70% of CAISO ancillary services were self-provided in 2002 and 2003.

In addition to these ancillary services procured daily by the CAISO, the following two ancillary services are procured through long-term contracts:

- **Voltage Support**: "Services provided by Generating Units or other equipment such as shunt capacitors, static var compensators, or synchronous condensers that are required to maintain established grid voltage criteria. This service is required under normal or system emergency conditions."

- **Black Start**: "The procedure by which a Generating Unit self-starts without an external source of electricity thereby restoring power to the ISO Controlled Grid following system or local area blackouts."

2.6.2 Quantity of Ancillary Services Procured

The quantity of ancillary services supplied to the CAISO varies hourly, both in terms of actual MW of services procured and as a percentage of load. Some of quantities are determined by Western Electricity Coordinating Council reliability criteria. For example, the quantity of operating reserves, including both spinning and non-spinning reserves, must be at least 5% of the load served by hydroelectric generators, and 7% of the load served by thermal generators. Of this, at least half must be spinning reserves. When operating reserves fall below this level, the CAISO declares an electricity supply emergency. The WECC does not require specific quantities of regulation and replacement reserves. For these services, the CAISO must exercise judgment as to how much capacity is required to ensure reliable operations.

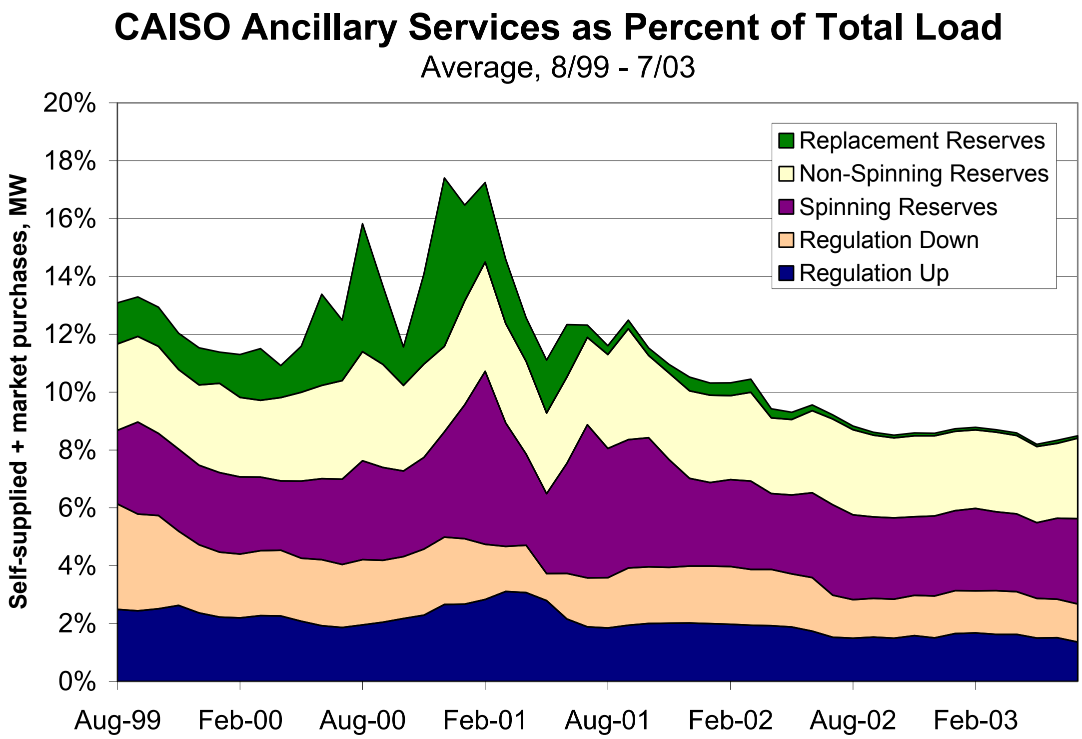

Figure 56: Quantity of ancillary services supplied to the California ISO. Shows data from August 1999 through July 2003, as a percent of load and includes both self-provided and ISO-procured ancillary services.

During the early years of the California market, the quantity of ancillary services procured was generally above 11% of the load in each hour, as is shown in Figure 56. The quantities were substantially higher during the crisis period of June 2000 through

June 2001, particularly replacement reserves. This was chiefly due to under-scheduling of load by California load-serving entities. Quantities declined steadily after the crisis period, from over 12% of load in fall 2001 to just over 8% in summer 2003.

Figure 57 shows the quantities of ancillary services supplied to the CAISO by hour of the day. The chart shows that the CAISO procures relatively small quantities at night (less than 2500 MW on average) and higher quantities during the daytime, cresting in late afternoon at the time of system peak load.

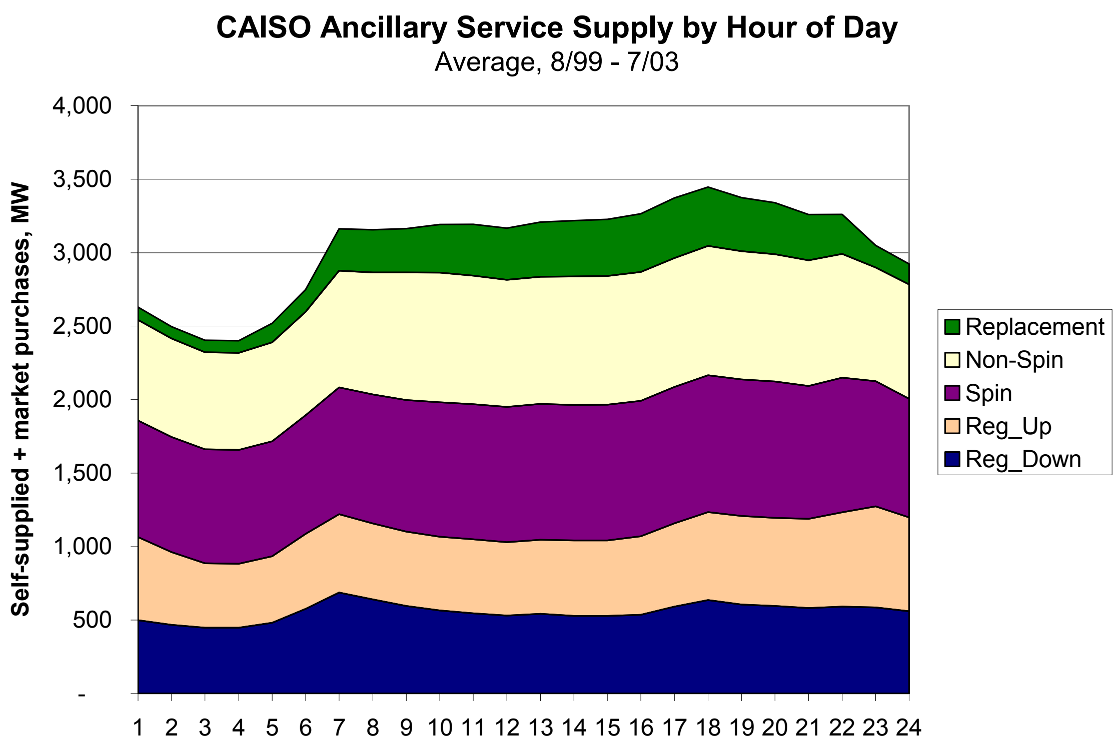

Figure 57: Quantity of ancillary services supplied to the California ISO, August 1999 through July 2003, by hour of day.
Includes both self-provided and ISO-procured ancillary services.

2.6.3 Effect of Load Reduction on Ancillary Service Quantities

Figure 57 indicates that the quantity of ancillary services supplied to the CAISO varies as a function of system load. However, the effect of load reductions on ancillary service quantities varies by the type of service.

- **Operating Reserves.** The WECC criteria for operating reserves are expressed as percentages of load. Thus, programs that reduce system load result in a one-to-one reduction in the requirement for operating reserves.

- **Regulation.** For regulation capacity, the requirement is a function not of the *size* of system load, but of the *variability* of system load. Load reductions might be expected to have a somewhat smaller effect on regulation quantities, because system variability does not necessarily vary one-to-one with total load. However, this effect is likely to be small and would be very difficult to estimate; thus, it is ignored for the purpose of our analysis and load reductions are assumed to result in a one-to-one reduction in the requirement for regulation capacity.

- **Replacement Reserves.** The CAISO procures replacement reserves when it believes that quantities of operating reserves are likely to be inadequate given system conditions. The quantities of replacement reserves procured show a clear pattern of varying with system load; thus, it is assumed that load reductions result in a one-to-one reduction in the requirement for replacement reserves.

- **Black Start and Voltage Support.** These services are procured by the CAISO under long-term contract. The requirement for black start capability is a function of what is needed to restore power after a widespread blackout, and is likely to be insensitive to loads. Reactive power requirements for voltage support might be reduced with lower system peak loads. However, this effect would be extremely difficult to estimate and is likely to be small. We therefore assume in this analysis that load reductions do not result in incremental savings in black start and reactive power requirements.

Thus, we assume load reductions result in a one-to-one reduction in the quantities of ancillary services procured in the CAISO's daily and hourly markets, and no reduction in the quantities of ancillary services procured under long-term contracts.

2.6.4 Ancillary Service price history

Figure 58 shows the history of ancillary service prices in CAISO hourly markets. With the exception of the crisis period, monthly average ancillary service prices have generally ranged between $5 and $15 per MWh of ancillary service supplied to the CAISO.[81] This represents approximately $0.50 and $2.00 per MW of load, or between 1% and 5% of total energy costs. Prices have been slightly higher in both the summer and the winter months than in the spring and fall. Peak period prices are generally, though not always, higher than off-peak prices.

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[81] In this analysis, ancillary services that are self-supplied are priced at the CAISO hourly clearing price. If all ancillary services are self-supplied in an hour, the hourly clearing price is assumed to be zero.

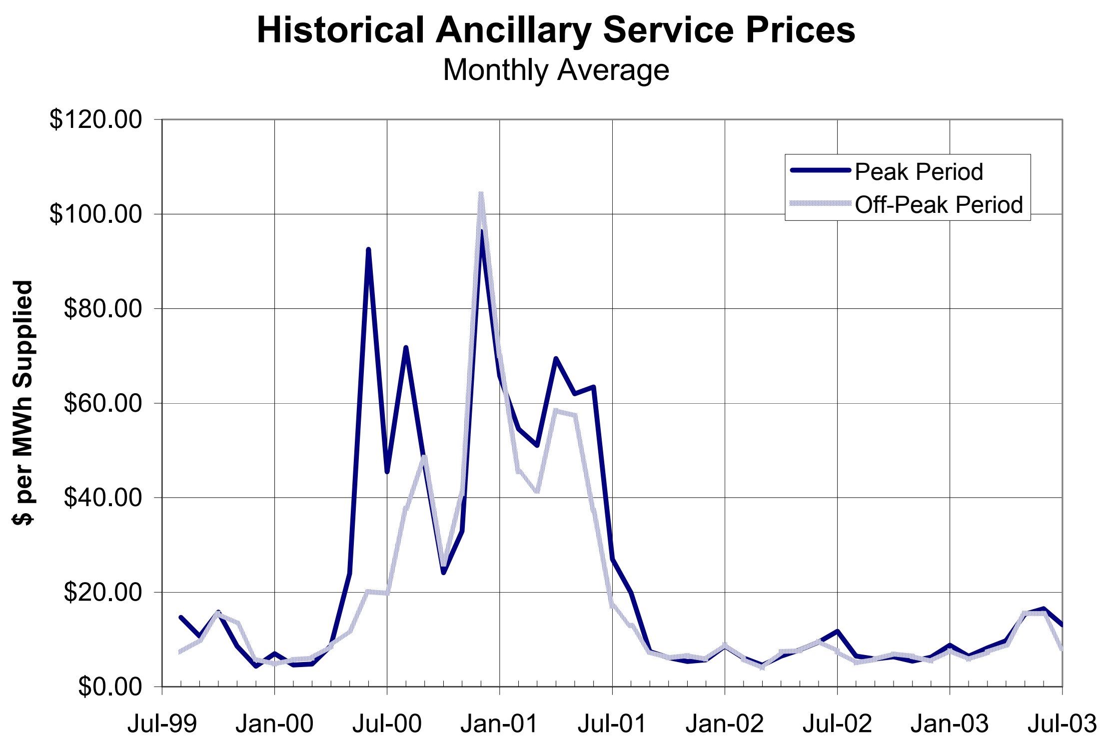

Figure 58: Historical California ISO ancillary service prices, averaged over a month.

There are two principal drivers of ancillary service prices: the variable costs of providing ancillary services, including fuel and incremental maintenance costs; and the opportunity cost of using generating capacity to provide ancillary services rather than energy. The former varies with fuel prices, while the latter varies with electric energy prices both in California and elsewhere in the WECC. Historical ancillary service prices are, as would be expected, highly correlated with electricity prices.

2.6.5 E3's Approach to Estimating Avoided Ancillary Service Costs

We have used a very simple approach to estimating avoided ancillary service costs: ancillary service costs are expressed as a straight percentage of the energy costs in a given hour, calculated from historical data. Ancillary service costs are thus expressed as a multiplier: Total Energy = Energy Commodity * (1 + A/S%). There are two principal reasons for adopting this simple approach. First, ancillary services are a relatively small part of the total avoided costs for any particular program. Thus, a more elaborate approach may not yield sufficient benefits to warrant the required investment of resources. Second, this approach provides inherent hourly ancillary service price variation, as energy prices vary according to a pre-defined price duration curve. Thus, the effect of high energy prices in a given hour is amplified by higher ancillary service prices, reflecting actual market experience.

The CAISO's Division of Market Analysis (DMA) reports monthly average ancillary service prices as a percent of total energy costs in its monthly "Market Analysis Reports".[82] Rather than duplicate this effort, E3 calculated the ancillary service multiplier as 1 plus the average of the monthly values reported by the DMA. In order to avoid overstating the long-run marginal cost of ancillary services, E3 ignored the data for the crisis period June 2000 through June 2001 because of the extreme effect of the crisis on CAISO ancillary service prices. E3 also ignored data from the period prior to June 1999 when the CAISO ancillary service markets were structured differently than they are today. For the remaining 30 months, ancillary service costs averaged 2.84% of total energy costs. E3 thus adopts 1.0284 as the ancillary service multiplier.

Figure 59 depicts historical and projected monthly average ancillary service costs using September 15, 2003, forward market prices for NP15 from Platts' *Megawatt Daily*. Projected monthly average costs range from $1.26/MWh of load for October 2003 to $1.54/MWh of load for the third quarter of 2004. These prices are slightly higher than 2002 prices but are significantly lower than prices during the 1999-2001 period.

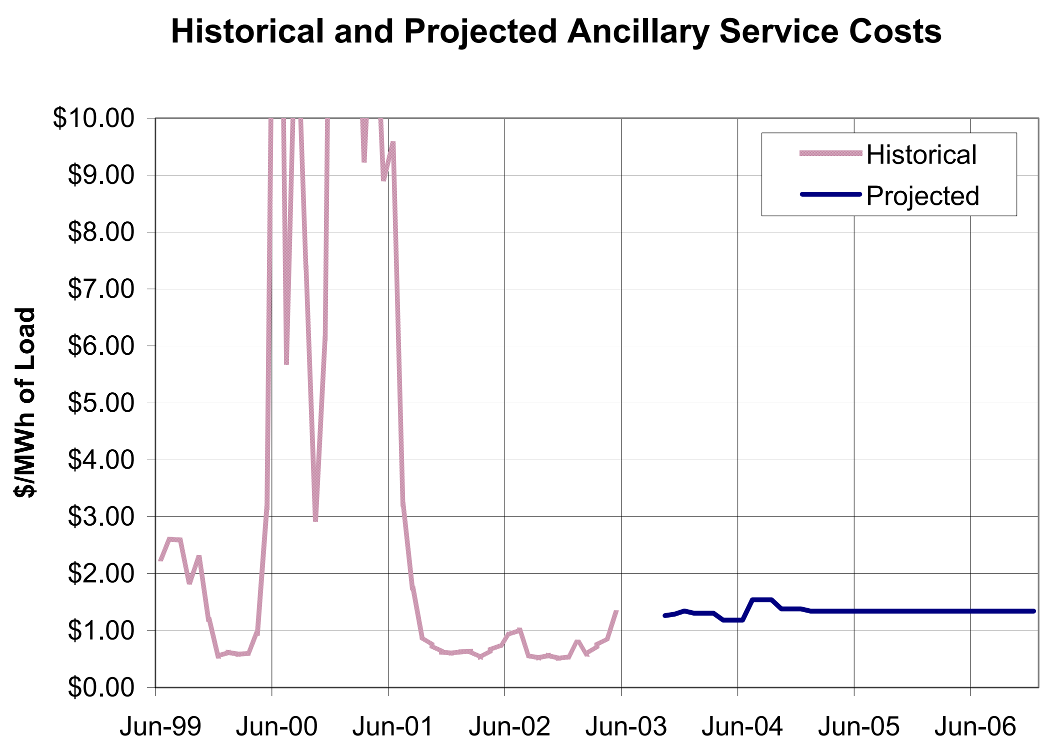

Figure 59: Historical and projected California ISO ancillary service costs in dollars per MWh of load.

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[82] These reports can be found on the CAISO website at http://www.caiso.com/docs/2000/07/27/2000072710233117407.html

Projected values are calculated using Platts' forward market prices for NP15.

2.6.6 Validation of E3's Approach through Incremental Cost Analysis

To validate this approach, E3 also estimated the incremental cost of purchasing and operating new generating capacity solely for the purpose of providing ancillary services. E3 does not recommend this alternative approach, because it is likely to be more economic to continue providing ancillary services with a mix of generating resources including existing hydro and thermal units, new units, and imports. However, this method should provide a cost ceiling to test the reasonableness of the E3 approach.

The incremental cost analysis assumes a carrying cost of $60/kW-yr. for a simple cycle combustion turbine. This cost is allocated over 8,760 hours and divided by an assumed availability rate of 90% and an ancillary services "load factor" of 58% (based on the historic average quantity procured each hour divided by the maximum quantity procured over the historic period). The result is an average capital cost of $13.16 per MWh of ancillary services procured.

A combustion turbine power plant will also incur some operating costs when providing ancillary services. Most importantly, the plant will suffer a heat rate penalty due to operating below maximum capacity. It is assumed that a CT providing regulation or spinning reserve services operates at an average loading of 75% of nameplate. This would increase the heat rate of a standard CT from 9,360 Btu/kWh to 10,790 Btu/kWh, a penalty of 1,430 Btu/kWh.[83] An additional penalty of 50 Btu/kWh is assumed to represent the incremental cost of cycling up and down for a plant providing regulation. No incremental operating costs are assumed for a plant providing non-spinning or replacement reserves. Regulation and spinning reserve comprise 38% and 30%, respectively, of total hourly ancillary service quantities. The heat rate penalties for each service are multiplied by the quantity weights for a final weighted heat rate penalty of 943 Btu/kWh. The resulting incremental cost will vary with the cost of fuel. Assuming gas costs $5/MMBtu, a new CT providing the full range of hourly ancillary services would operate with costs of $4.94/MWh of ancillary services provided.[84]

The total cost of $18.16/MWh of ancillary services provided is multiplied by 10.55%, which is the average quantity of ancillary services as a percentage of load. This yields a final ancillary service cost of $1.91 per MWh of load when gas costs $5/MMBtu. This estimate is somewhat higher (30-60¢, or 20-50%) than the E3 projections, but substantially below actual ancillary service costs during the crisis period. The result therefore provides validation for the reasonableness of E3's simple approach.

2.7 Price Elasticity of Demand Adder

This section estimates "[a] stream of hourly values for the years 2004-2023, of the quantified price elasticity of demand benefits resulting from reduced electricity and

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[83] Heat rate numbers based on a GE 7FA turbine at standard temperate and pressure.
[84] Plants providing ancillary services, in particular regulation and spinning reserves, are also likely to incur additional costs in the form of more frequent maintenance requirements. However, a maintenance penalty is likely to be small, and is therefore ignored for this validation analysis.

natural gas consumption. In the context of a deregulated energy market, the price elasticity values should reflect the value of reduced energy usage based on its effect on reducing day-ahead market prices through demand reduction.” (RFP, page 8). Since the forecast of spot gas price does not vary with in-state gas consumption, the value of gas demand reduction is captured in the gas price forecast. Therefore, E3’s focus was on the effect of electricity demand reduction on day-ahead electricity market prices.

The section’s key findings are:

1. A conservative, yet reasonably accurate, way to capture the system value of demand reduction is through a multiplier: [1 + Elasticity of MCP with respect to load * Utility distribution company’s (UDC’s) residual net short (RNS) as a percent of load].

2. The MCP elasticity measures the percent change in MCP due to one percent change in load. It is computed as (a) the dollar change in MCP per unit load change, times (b) the load-to-MCP ratio. The on-peak MCP elasticity can be less than the off-peak elasticity if the dollar change in MCP per unit load change is similar for both periods and the on-peak load-to-MCP ratio is smaller than the off-peak ratio.

3. Based on the California Power Exchange’s (PX) day-ahead hourly unconstrained price data for 04/01/98-04/30/00, the system MCP elasticity estimates by month and

time-of-use period are given in Figure 60.

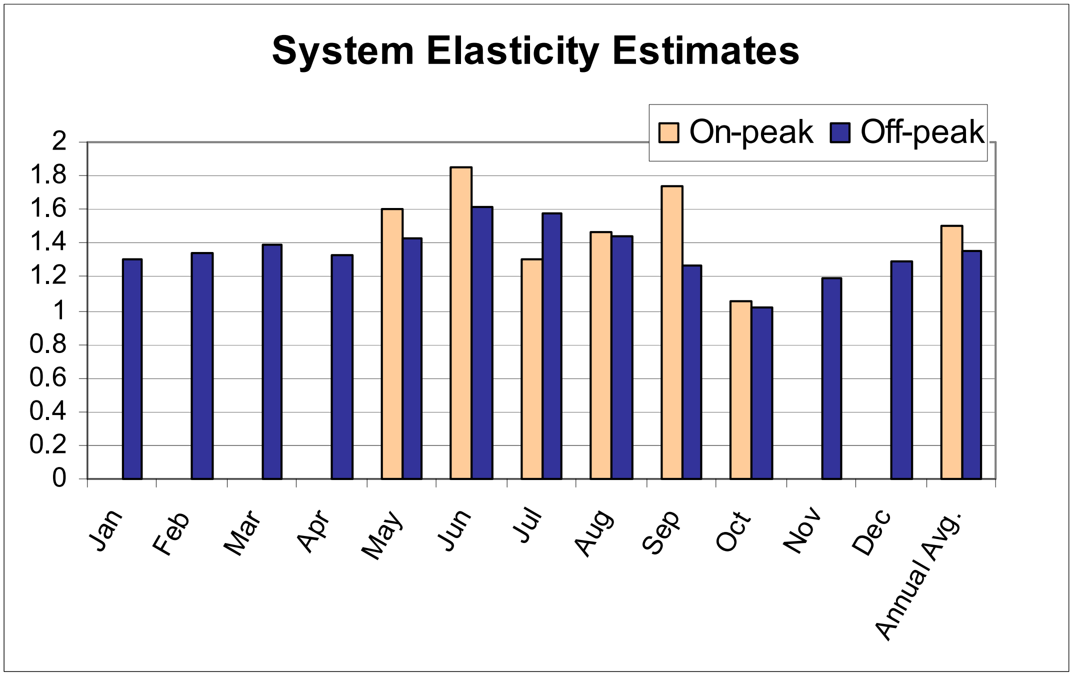

Figure 60: Monthly system average price elasticity estimates

Based on the CPUC staff's suggested on-peak period (08:00 – 18:00, working weekdays during summer: May – October,) and the off-peak period (all other hours).

4. Under load-resource balance with easy entry, an electricity supply curve is flat, defined by the long-run marginal cost (LRMC). Hence, during load-resource balance years, a demand reduction has zero price effect and the MCP elasticity estimates are zero as well.

5. Linear trending yields the projected values for the period between the estimates in Figure 60 and the year of load-resource balance. Assuming a 5% RNS value,[85] one can readily compute the demand reduction multiplier using the formula in Finding #1 above. Table 33 presents the annual multiplier values E3 calculated assuming a load-resource balance year of 2008.

Table 33: Projected on-peak multipliers from 2004 to the assumed load-resource balance year of 2008

Year	System-Wide Projected Multipliers
2004	1.08
2005	1.06
2006	1.04
2007	1.02
2008	1.00

2.7.1 Background

The 09/06/00 Assembly Bill (AB) 970 (Ducheny) requires "[r]e-evaluation of all efficiency cost-effectiveness tests in light of increases in wholesale electricity costs and of natural gas costs to explicitly include the system value of reduced load on reducing market clearing prices and volatility." (Section 7(b)(8)). The economic rationale of this requirement is that demand-side-management (DSM) and energy-efficiency (EE) programs reduce the electricity demand of program participants and shift the market

[85] The 09/26/03 meeting on the adder for electricity demand reduction indicates that the RNS stream may not be available from publicly available documents. However, such information is available from procurement reports filed by the UDCs to the CPUC.

demand curve downward along a given market supply curve, thus effecting a price reduction that can benefit all electricity consumers.[86]

The California Measurement Advisory Committee (CALMAC) acknowledges the importance of the price effect of a system demand reduction and establishes the use of escalators (or multipliers) for the purpose of quantifying the system benefit of a load reduction.[87] The October 2000 ALJ ruling affirms the use of multipliers: (p.13, "[t]he escalators are determined by looking at the 'load reduction value' or 'consumer surplus' relative to the market price and taking a ratio. The escalators are multiplied by the market price – either during peak or off-peak – to arrive at system value."

When a UDC relies entirely on the spot market for its procurement needs, a multiplier magnifies the generation avoided cost by (1 + MCP elasticity),[88] since the entire load is effected by the price decrease. Table 34 summarizes the prior multiplier values used in California and the implied MCP elasticity estimates.

Table 34: Prior multiplier values and the implied MCP elasticity estimates in California

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[86] A system demand reduction can decrease market prices in three specific and important ways. First, it reduces the output from units with high marginal production cost that drives the price offers of those units. Second, it can mitigate capacity shortages, thus diminishing the above-marginal-cost markup (i.e., shortage cost) required to balance system demand and supply. Third, it can counter energy sellers' market power, the ability to raise market prices through capacity withholding.

[87] CALMAC (2000) *Avoided Cost*, Report on Public Workshops on PY 2001 Energy Efficiency Programs, 09/12/00 – 09/21/00 and 09/26/00, California Measurement Advisory Committee (CA: San Diego).

[88] Woo. C.K. and D. Lloyd (2001) *Assessment of the Peak Benefit Multiplier Effect: (a) Economic Theory and Statistical Specification; and (b) Theory, Estimation and Results*, reports submitted to Pacific Gas and Electric Company.

Source	On-peak hours	Off-peak hours	Remarks
ALJ's 10/25/00 Ruling	• 4.0X [3.0] for 2001-2002 • 3.5X [2.5] for 2003-2005 • 3.0X [2.0] for 2006-2025	• 2.0X [1.0] for all years	These MCP elasticity estimates recognize the price effect of demand reduction is likely greater in the on-peak hours than off-peak hours.
CALMAC 2000 report	• 5.0X [4.0] when market power present • 2.5X [1.5] when market power absent	• Not available	These MCP elasticity estimates recognize that the price effect of demand reduction increases with market power.
E3's 2001 report[89]	• 4.1X [3.1]	• 1.8X [0.8]	These estimates are comparable to those in the ALJ's ruling
CPUC's Energy Efficiency *Policy Manual* (Draft: November 29, 2001)	• 5.0X [4.0] for 2002 • 2.0X [1.0] for 2003-2005 • 1.5X [0.5] for 2006-2001	• Not available	The estimates for 2003 and beyond are similar to those in Figure 60

In addition to Table 34, we researched "the values used by other state, national, and international agencies, where energy commodities are traded on an open market, for quantifying the price elasticity of demand benefits of electricity and natural gas demand reductions." (RFP, page 8).[90] This research yielded two publications supporting the

[89] Woo. C.K. and D. Lloyd (2001) *Assessment of the Peak Benefit Multiplier Effect: (a) Economic Theory and Statistical Specification; and (b) Theory, Estimation and Results*, report submitted to Pacific Gas and Electric Company.

[90] Our literature search began by checking all issues since 2000 of *Energy Journal*, *Energy Policy*, *Energy-The International Journal,* and *Electricity Journal*. It was followed by an internet search of the following key words: "price load", "electricity multiplier", and "electricity escalator".

hypothesis that MCP and load are positively correlated.[91] However, neither paper quantifies the effect of demand reduction on MCP.

2.7.2 Theory

Price effect of demand reduction

Economic intuition suggests that a demand reduction due to DSM and EE programs shifts the market demand curve downward along a given market supply curve, as portrayed by Figure 61. As a result, the MCP declines. This price effect is larger when the market equilibrium is near market supply capacity.

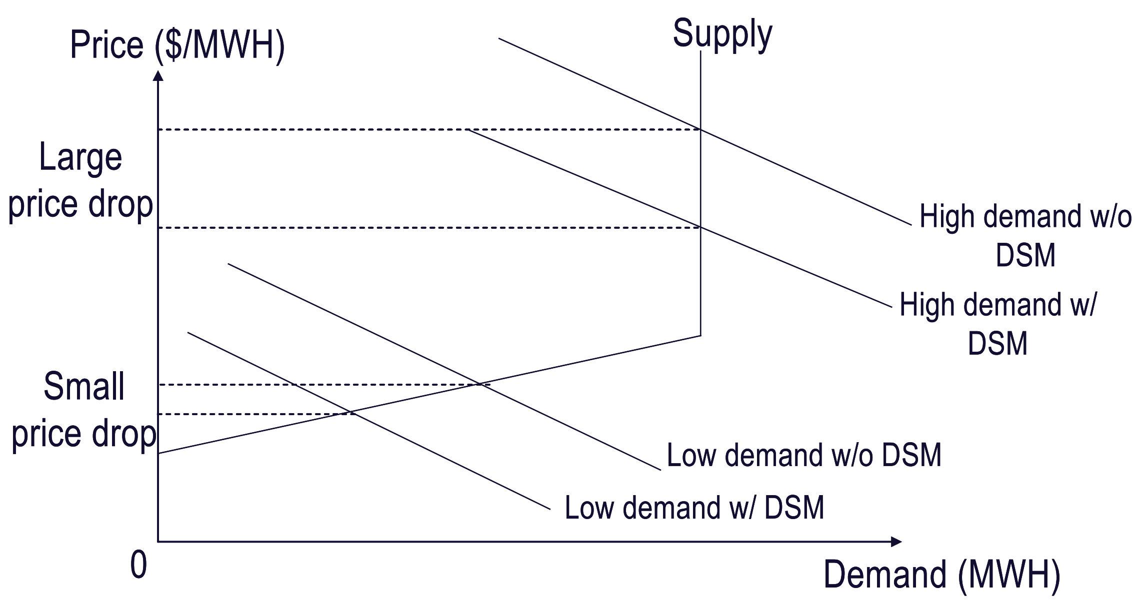

Figure 61: The effect of demand reduction on market-clearing price

[91] Li, Y. and P.C. Flynn (2004) "Deregulated Power Prices: Comparison of Diurnal Patterns," Energy Policy, 32: 657-672; Vucetic, S., K. Tomsovic and Z. Obradovic (2001) "Discovering Price-Load Relationships in California's Electricity Markets," *IEEE Transactions on Power Systems* 16(2): 280-286.

Multiplier

The benefit to an electricity consumer resulting from a price drop is his/her gain in consumer surplus (CS). This CS gain consists of (1) the bill saving directly attributable to the price drop, and (2) the benefit from incremental consumption induced by the price drop. When the consumer's individual demand is highly price insensitive, the incremental consumption (and therefore its ensuing benefit) is small, close to zero. In this case, the CS gain is mostly bill savings as shown in Figure 62.[92]

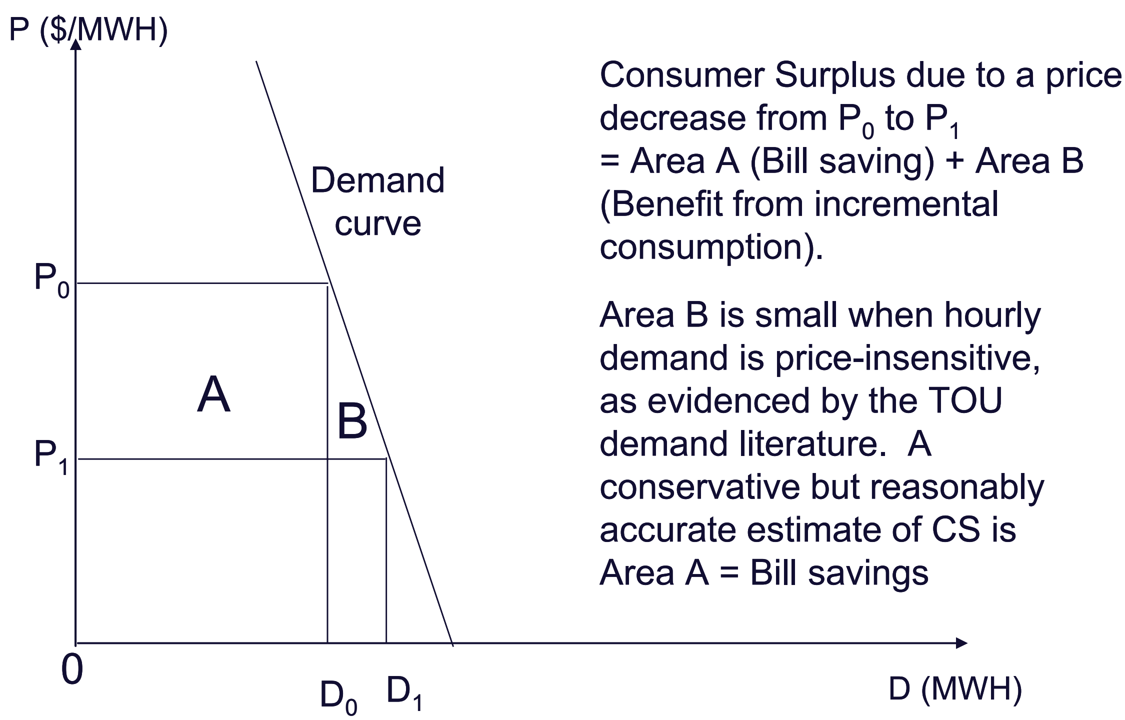

Figure 62: Consumer surplus and bill savings

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[92] Woo, C.K. (1984) "A Note on Measuring Household Welfare Effects of Time-of-Use Pricing," *Energy Journal*, 5:3, 171-181.

Our approach for estimating consumer gains from a market price decline assumes that a UDC transacts its RNS at day-ahead market prices. The RNS is the difference between (a) the UDC's total bundled service demand and (b) output of the UDC's retained generation and share of the California Department of Water Resources (CDWR) contracts. These two assumptions imply that the total bill for generation is

$$B \quad = \quad F + P\,(q - Q) + c\,Q,$$

where F = fixed cost of CDWR contracts and retained generation, P = price applicable to the RNS (q – Q), q = total bundled service demand, and Q = output from CDWR contracts and retained generation, c = per MWh variable cost to produce Q because most CDWR contracts are tolling agreements and retained generation has fuel and variable O&M costs.

Now, the change in B due to a change in q is:

$$\Delta B \quad = \quad P\,(\Delta q - \Delta Q) + (q - Q)\,\Delta P + c\,\Delta Q + Q\,\Delta c,$$

because a change in q can potentially affect P, Q, and c. Based on the ALJ 10/25/00 Ruling, the multiplier is a scalar ω such that ω P measures the change in bill per MWH change in q:

$$\omega P \quad = \quad \Delta B / \Delta q$$

$$= \{1 + [(q - Q) / q] (q / P) (\Delta P / \Delta q) + (c\, Q / P\, q) (q / c)(\Delta c / \Delta q) -$$

$$[(P\text{-}c)\, Q / P\, q] (q / Q)(\Delta Q / \Delta q)\}\ P.$$

As a result,

$$\omega = 1 + s\, \varepsilon_1 + r\, \varepsilon_2 - w\, \varepsilon_3; \qquad (1)$$

where $s = (q - Q) / q$ = RNS as a percent of total bundled service load, $\varepsilon_1 = (q / P) (\Delta P / \Delta q)$ = MCP elasticity with respect to bundled service load, $r = c\, Q / P\, q$ = ratio of total variable cost of CDWR and retained generation to market value of retail sales, $\varepsilon_2 = (q / c)(\Delta c / \Delta q)$ = elasticity of CDWR contracts' and retained generation's per MWh cost with respect to retail sales, $w = [(P\text{-}c)\, Q / P\, q]$ = market-based margin from CDWR and retained generation as a percent of market-based retail revenue, and $\varepsilon_3 = (q / Q)(\Delta Q / \Delta q)$ = elasticity of output from CDWR contracts and retained generation with respect to retail sales.

Equation (1) can be simplified to

$$\omega = 1 + s\, \varepsilon_1 \qquad (2)$$

for two reasons. First, $\varepsilon_2 = 0$ because a small change in bundled service demand has little, if any, effect on the average (not marginal) cost of a UDC’s retained generation and

CDWR contracts. Second, $\varepsilon_3 = 0$ because each UDC's hourly dispatch is driven by market conditions.[93]

Equation (2) differs from the multiplier formula of $(1 + \varepsilon_1)$ in E3's 2001 report because a UDC's retained generation and share of CDWR contracts now relieve the UDC from complete reliance on the spot market for its procurement needs.

Market-clearing price regressions

The multiplier formula given by equation (2) requires MCP elasticity estimates. As in our 2001 report, we estimated 24 hourly MCP linear regressions.[94] Each regression's dependent variable is the system MCP for that hour, chosen to be the PX day-ahead unconstrained hourly price[95]. The independent (explanatory) variables are as follows:

1. Hourly market clearing MWh at the PX day-ahead unconstrained MCP.

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[93] To understand why $\varepsilon_3 = 0$, consider the following cases:

- Shortage: All units are already at full capacity and a small reduction in bundled service demand does not alter the units' output.
- No shortage but high prices: All units with short-run marginal cost below spot price are dispatched, without reference to the level of bundled service demand.
- No shortage but low prices: Reduction in bundled service demand reduces the UDC's economic purchases, but not the output of the UDC's units (e.g., nuclear or run-of-the-river hydro) that are already on line because of their below-market short-run marginal cost.

[94] Woo. C.K. and D. Lloyd (2001) *Assessment of the Peak Benefit Multiplier Effect: (a) Economic Theory and Statistical Specification; and (b) Theory, Estimation and Results*, report submitted to Pacific Gas and Electric Company.

[95] There are no quantity data for day-ahead spot electricity by location (e.g., NP-15 and SP-15), even though there are price data by location. The lack of matching quantity and price data by location precludes a meaningful locational MCP regression analysis. Even though we did estimate NP-15 and SP-15 MCP price regressions with CAISO's NP-15 and SP-15 scheduled loads being part of the set of explanatory variables, those locational MCP regressions yield counter-intuitive results. In particular, the on-peak MCP elasticity estimates are typically less than the off-peak estimates; and the NP-15 estimates are much smaller than the SP-15 estimates.

2. Input prices: system average natural gas price,[96] California-Oregon-Border (COB) price and Palo Verde (PV) price. The gas price appears in the MCP regression because it directly affects the marginal fuel cost of in-state generation. The COB and PV prices enter the MCP regression because COB and PV are wholesale markets inter-connected with the California market; and a trader, for example, can buy electricity at COB or PV and sell that electricity into California.

3. Hydro output levels inside and outside California. Economic dispatch by hydro owners (e.g., BPA and BC Hydro) in response to high demand helps suppress MCP.

4. Binary indicators for Stage 1 and Stage 2 emergency actions, as there were no Stage 3 emergencies during the modeling period. These indicators aim to isolate the price effects of imminent or actual capacity shortages.

5. Binary indicators for weekend/holiday and month-of-year. These indicators capture the price effect of weekday/holiday and seasonality.

Since hourly demand is mainly driven by weather, weather does not enter into the MCP regression as an additional explanatory variable. However, as explained below, the weather data are used by an (instrumental variable) estimation procedure to obtain unbiased regression coefficient estimates.

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[96] This is the load-weighted average of PG&E Citygate and SoCal gas prices, with weights being the NP-15 and SP-15 loads. We did not include PG&E Citygate and SoCal gas prices as separate explanatory variables because of their high correlation that leads to imprecise coefficient estimates with wrong signs.

Except for point #5, the explanatory variables are likely correlated with the random error term of the MCP regression. To see this point, consider the following examples:

- A random surge in out-of-state demand raises the MCP, COB, and PV prices.
- A random plant outage that raises the MCP also causes Stage 1 and Stage 2 emergency actions.
- An unexpectedly wet year that suppresses the MCP increases hydro output.

This correlation between the explanatory variables and the error term implies that coefficient estimates found using ordinary least squares (OLS) method are biased. Hence, we apply the instrumental variable (IV) method that yields unbiased estimates in a large sample.[97]

2.7.3 Sample Selection

Empirical implementation of the MCP regression requires selecting a suitable sample. Table 35 lists the data available from public sources.

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[97] For an explanation of the IV method, also known as two-stage-least-squares (2SLS), see Chapter 13, Kmenta J. (1971) *Elements of Econometrics*, MacMillan, NY: New York. The list of instruments used here includes (a) binary indicators for year, weekend/holiday and month-of-year; (b) Henry Hub daily spot gas price; (c) in-state and out-of-state nuclear production; and (d) weather from nine stations: Burbank, Fresno, Long Beach, Riverside, Sacramento, San Diego, San Francisco, San Jose, and Ukiah. The SAS programs used to construct the data sample and perform the estimation are provided in a separate binder. The same binder also contains the regression output.

Table 35: Publicly available data for electricity price elasticity of demand estimation

Data	Duration	Source	Remarks
PX day-ahead zonal electricity prices	04/98 – 01/01	University of California Energy Institute (www.ucei.berkeley.edu/ucei/datamine/datamine.htm)	California PX day-ahead NP-15 and SP-15 zonal (constrained) market-clearing prices for delivery during each hour of the following day.
PX day-ahead unconstrained electricity prices and quantities	04/98 – 01/01	University of California Energy Institute	California PX day-ahead unconstrained market-clearing prices and quantities for delivery during each hour of the following day.
CAISO real-time electricity prices	04/98 – present	University of California Energy Institute	Hourly ex-post zonal prices at NP-15 and SP-15
CAISO scheduled loads	04/98 – present	University of California Energy Institute	System and zonal (NP-15 and SP-15) scheduled by the CAISO
In-state bilateral trading electricity prices	01/99 – present	Platts Energy	NP-15 and SP-15 on-peak (06:00-22:00, Mon-Sat) and off-peak (remaining hours) prices for next day delivery
Out-of-state bilateral trading electricity prices	01/97 – present	Platts Energy	California Oregon Border (COB) and Palo Verde (PV) prices on-peak (06:00-22:00, Mon-Sat) and off-peak (remaining hours) prices for next day delivery
Gas Prices (PG&E Citygate, SoCal, Henry Hub)	04/98 – present	Platts Energy	Daily spot prices for gas delivered at PG&E Citygate, SoCal, and Henry Hub. The Henry Hub price is used as an instrument in the 2SLS estimation.
Hydro and Nuclear Production	04/98 – 12/02	Dept. of Energy EIA-906 (monthly utility power plant) database	Hydro and nuclear output by plant: WA, OR, CA, NV, ID, MO, WY, UT, CO, AZ, NM, which are summarized as total monthly output: CA-

			only and outside CA
Weather for nine CA stations: Burbank, Fresno, Long Beach, Riverside, Sacramento, San Diego, San Francisco, San Jose, Ukiah	04/98 – present	CEC	Daily: min, max, and avg. temp; cooling degree days; heating degree days. Used as instruments in 2SLS estimation.
CAISO Declared Emergencies	04/98 – present	CAISO event log	Each emergency hour is either stage 1, 2, or 3
Price Caps	04/98 – present	FERC orders and its 2003 Final Report on Price Manipulation in Western Markets.	Soft caps beginning 12/08/00; complicated rules 05/29/01 – 07/12/02

Based on the data described in Table 35, Figure 63 suggests three distinct periods:

1. **Pre-crisis** (04/01/98-04/30/00) in which the PX was in operation, electricity prices were below the CAISO's caps, gas prices were moderate, and the number emergency hours was low.

2. **Crisis** (05/01/00 – 06/30/00) in which the PX shut down on 02/01/01, prices often hit the CAISO's caps, gas prices were high, and emergency hours were many.

3. **Post-crisis** (07/01/01 – Now) in which electricity prices were low and below the CAISO's low caps, gas prices were moderate, and emergency hours were few.

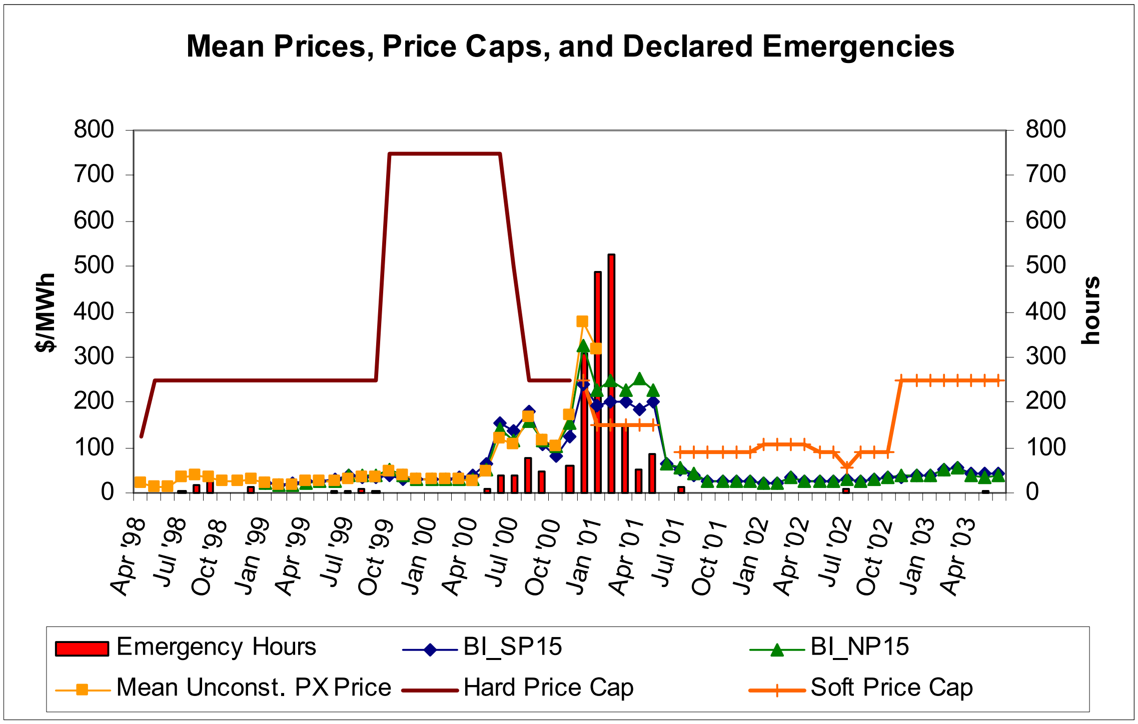

Figure 63: Mean Prices, Price Caps, and Declared Emergencies "BI" = Bilateral Trading

We constructed our sample using the following criteria: (a) publicly known and reliable data sources; (b) reasonable representation of a workably competitive market environment; and (c) correct measurement of day-ahead MCP for spot electricity and market-clearing MWh at those prices. A sample meeting these criteria contains PX day-ahead unconstrained hourly prices in the pre-crisis period as the dependent variables of the MCP regressions, plus the associated observations of the independent (explanatory) variables described in the subsection 2.7.2 above.

Table 36 reports the pair-wise correlation between hourly PX price by location and each of the following variables: hourly load by location, gas price by location, COB price and PV price.

Table 36: Pair-wise correlation between PX day-ahead unconstrained hourly price and its drivers for the pre-crisis period: 04/01/98-04/30/00

Variable	Correlation coefficient
PX day-head MWh at the unconstrained PX prices	0.65
PG&E city gate gas price	0.40
SoCal gas price	0.33
COB price	0.72
PV price	0.66
In-state hydro output	-0.19
Out-of-state hydro output	-0.27

The positive correlation coefficients in the above table indicate that the MCP varies directly with demand level, gas prices, and out-of-state wholesale market prices. The two negative correlation coefficients show that the MCP declines when hydro output increases. To isolate the effect of demand reduction from the joint effect of changes in other variables (e.g., gas prices), however, requires an estimation of hourly MCP regressions.

We applied the following steps to find the price effect of a load reduction:

1. Estimate each hourly MCP regression using the full set of explanatory variables: MWh at MCP, gas price, wholesale market prices, in- and out-of- state hydro output, emergency indicators, and binary indicators for weekend/holiday and month-of-year.

2. Re-estimate the MCP regression after excluding input price variables that have negative coefficient estimates. For instance, if the PV price coefficient estimate is negative because of the high collinearity between COB and PV prices, the PV price variable is excluded in the re-estimation.

2.7.4 MCP Elasticity Estimates

Computation method

Computing the MCP elasticity, $\varepsilon_1 = (q / P) (\Delta P / \Delta q)$, entails the following steps:

1. Simulate the effect of a 5% load reduction on the MCP for each observation in the sample. The assumed 5% reduction aims to capture the price effect of preempting an emergency via EE and DSM programs.

2. Compute the observation-specific ε_1 as the percent change in MCP due to 1% change in load.

3. Find the average MCP elasticity as the arithmetic mean of the observation-specific ε_1 values.

System average elasticity estimates

Figure 64 displays the diverse elasticity estimates by month and hour.

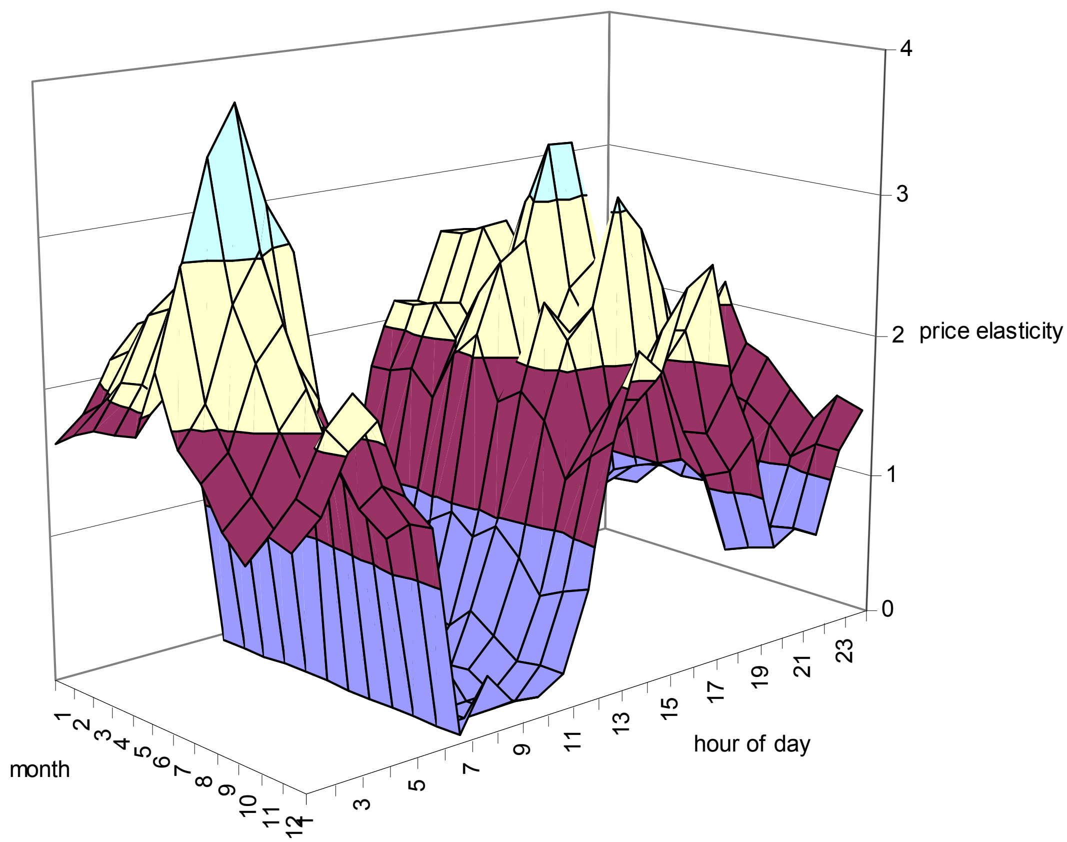

Figure 64: MCP elasticity estimates by month and hour based on PX day-ahead unconstrained prices and demands

Note when looking at Figure 64 that during the hours from 08:00 to 12:00, elasticities are very low or zero. As seen below, this has an impact on the overall estimates for the on- and off-peak periods, as the hours 08:00 – 12:00 make up part of the on-peak period as defined herein. A plausible explanation for the very low elasticities during these hours is that cycling units with similar marginal costs are brought on line to meet the day's rising loads during these and later hours, and therefore the marginal cost curve during these hours is flat or nearly flat.

Elasticities are aggregated to the monthly level in Figure 65.

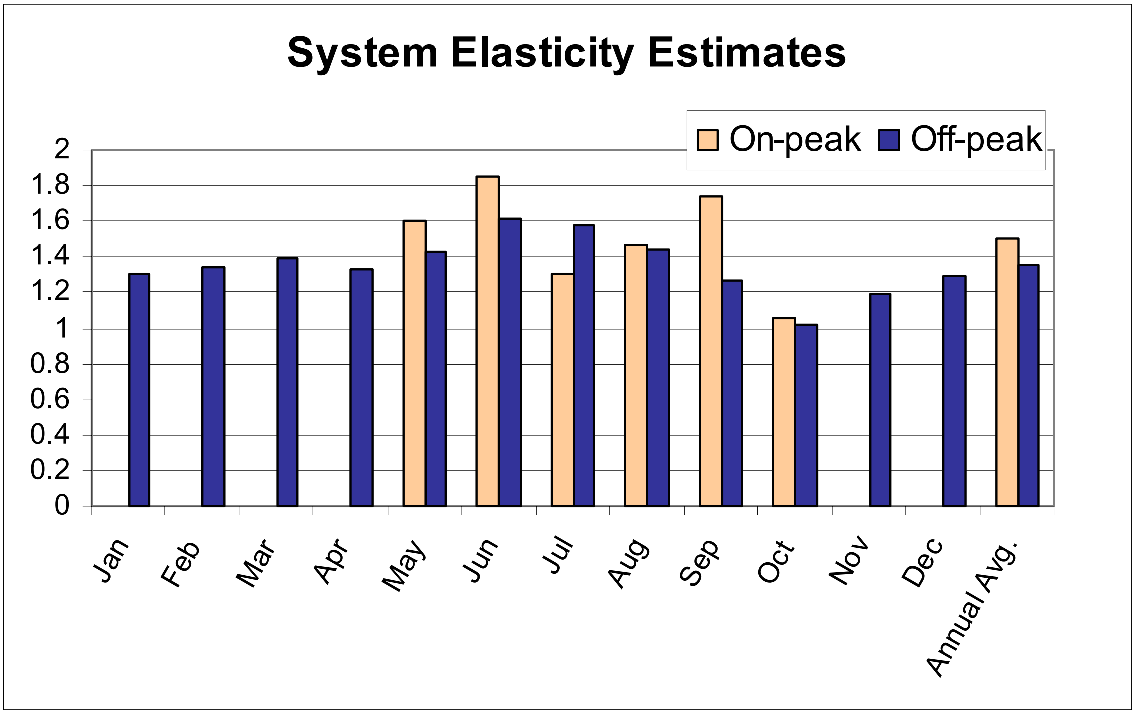

Figure 65: Monthly system average price elasticity estimates
Based upon the CPUC staff's suggested on-peak period (08:00 – 18:00, working weekdays during summer: May – October,) and the off-peak period (all other hours).

Figure 65 shows that the monthly system average elasticity estimates range from 1.05 to 1.85 in the on-peak period, yielding an annual average of 1.50. The on-peak estimates are lower than the values adopted in the October 2000 Administrative Law Judge ruling,[98] and those in the CALMAC's September 2000 report,[99] and E3's 2001 research report.[100] This is because:

- The prior values were based on data samples that include summer 2000 when prices spiked during the on-peak hours. As a result, a given load reduction would have a greater impact on MCP than those reported herein.

- The on-peak period definition used herein has been shifted from prior studies to include the morning hours 08:00 – 12:00, when elasticities are zero or very low. E3's 2001 report, for example, defined the peak period as 12:00-18:00, working weekdays.

However, the estimates in Figure 65 are similar to those for 2003 and beyond in the CPUC's Energy Efficiency Policy Manuel (Table 4.5, Draft: November 29, 2001).

The off-peak elasticity estimates in Figure 65 are between 1.02 and 1.62, yielding an annual average of 1.35. They are higher than the prior values in the October 2000 Administrative Law Judge ruling and E3's 2001 research report, again because of the shifting of on- and off-peak period definitions.

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[98] Issued on 10/25/00 on *Applications 99-09-049, 99-09-050, 99-09-057 and 99-09-058*.
[99] CALMAC (2000) *Avoided Cost*, Report on Public Workshops on PY 2001 Energy Efficiency Programs, 09/12/00 – 09/21/00 and 09/26/00, California Measurement Advisory Committee (CA: San Diego).
[100] Woo. C.K. and D. Lloyd (2001) *Assessment of the Peak Benefit Multiplier Effect: (a) Economic Theory and Statistical Specification; and (b) Theory, Estimation and Results*, report submitted to Pacific Gas and Electric Company.

2.7.5 Forecasting the Multiplier Values

Projecting the MCP elasticity estimates

The MCP elasticity estimates in Figure 65 correspond to a period when resource and load are not in balance. These estimates form our starting point for 2004. When resource and load are in balance, a small demand change along a flat supply curve, defined by the long-run marginal cost (LRMC), does not have a price effect. As a result, the MCP elasticity estimates under resource-load balance are zero. We find the estimates for the years between 2004 and the year of resource-load balance by linear interpolation.

Projecting RNS estimates

Due to the lack of publicly available information on each UDC's RNS, we assume that the on-peak estimates are 5% and the off-peak estimates are 0% for all years up to resource-load balance.

Projected multipliers

Table 37 presents our projected on-peak multipliers (= 1 + projected RNS * projected MCP elasticity) for 2004 to the year of resource load balance (assumed to be 2008). These multipliers are close to 1.0 as a direct result of the 5% on-peak RNS assumption. If RNS estimates were greater, the multiplier would be correspondingly higher as well.

Table 37: Projected on-peak multipliers from 2004 to the assumed load-resource balance year of 2008

Year	System-Wide Projected Multipliers
2004	1.08
2005	1.06
2006	1.04
2007	1.02
2008	1.00

The projected off-peak multiplier for all years is 1 because RNS is assumed to be zero in the off-peak period.

2.8 Natural Gas Avoided Cost

The RFP requires natural gas avoided cost forecasts "based on prices in the natural gas trading markets where natural gas is purchased for California consumers." E3 meets this requirement by using market data, to the extent they are available, to develop a forecast of monthly commodity prices for the SoCal Gas and PG&E Citygate pricing points. We used the PG&E Citygate price to represent avoidable commodity costs for customers on the PG&E system, while the SoCal Gas price represents avoidable commodity costs for customers on both the SoCal Gas and SDG&E systems. We describe in this section the derivation of the commodity price forecast for core customers of Local Distribution Companies (LDCs) and the delivered cost of natural gas to electricity generators. In previous sections of this report, we addressed the environmental and transportation avoided costs associated with core customer natural gas consumption.

E3's approach involved taking advantage of market data that reflect expectations of future prices in natural gas spot markets. The most important data are the prices of natural gas futures contracts for delivery to Henry Hub, Louisiana, traded on the New York Mercantile Exchange (NYMEX). In the near-term, when gas futures prices are available, California gas prices are forecast as NYMEX futures prices plus a basis differential reflecting the market value of transportation between California and Henry Hub. For years beyond the NYMEX trading data, we employed forecasts of natural gas prices from the CEC.

Figure 66 presents the results of E3's application of this methodology. Prices decline somewhat during the early years, but are generally flat between 2006 and 2009. After 2009, the CEC forecasts prices to increase gradually in nominal terms, reaching $8/MMBtu around 2022. Prices are slightly higher for PG&E than for SoCal gas during the early years, reflecting basis swap prices that indicate a larger basis differential from Henry Hub. After 2009, the CEC expects gas prices to be slightly lower for PG&E.

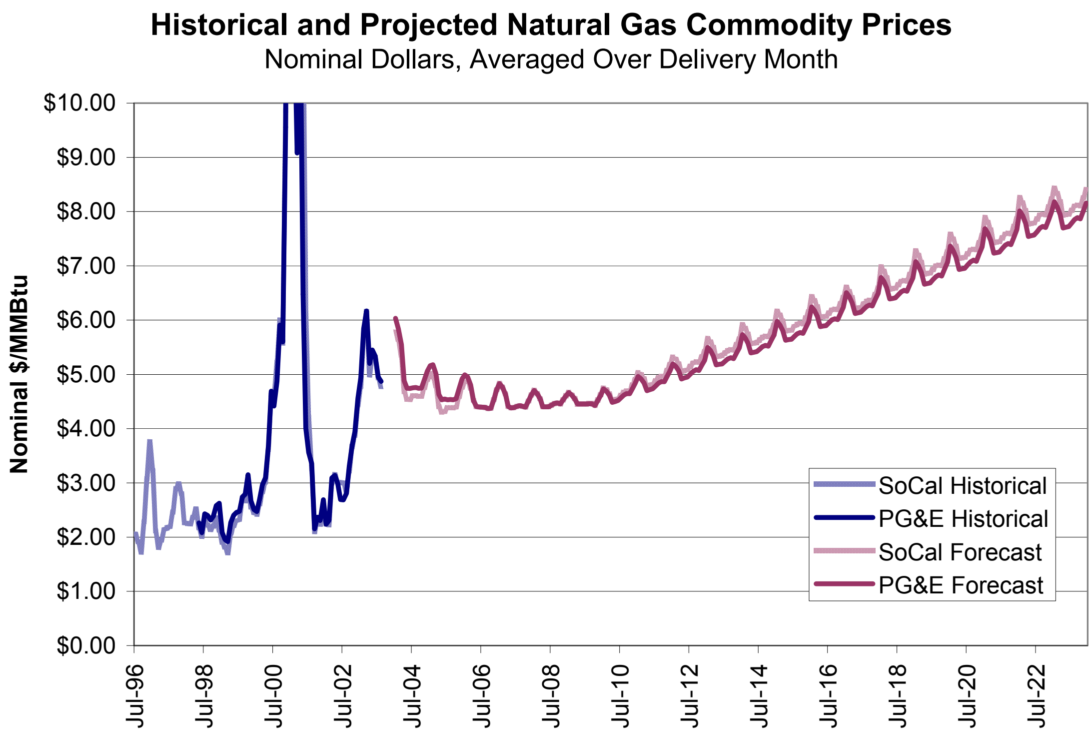

Figure 66: Historic and projected monthly average of natural gas commodity prices. The historic daily prices come from Platts' *Gas Daily*. The projected prices for 2004-2009 are based on NYMEX gas futures and basis swaps settlement prices for October 15, 2003. The projected prices for 2010-2022 are based on the California Energy Commission, *Natural Gas Market Assessment*.

2.8.1 Background

Continental natural gas market

Natural gas delivered to California consumers is traded in an aggregate wholesale market that spans most of North America.[101] Natural gas is produced at many locations, the most important of which are the Gulf of Mexico, southern Great Plains, Western Canadian

Sedimentary Basin, and the Rocky Mountains regions. Interstate natural gas pipelines transport the gas from the wellhead to wholesale market centers or "pricing points", where buyers include marketers, large retail customers, electric generators, and LDCs that purchase gas on behalf of small retail customers. These points are typically intersections of major pipelines, where buyers and sellers from different regions interact to form a spot market.

Spot gas trading

Spot gas is traded in monthly and daily packages. Monthly deals are made during the last week of each month ("bid week") for delivery the following month. Daily trading is generally for delivery the following day. Spot gas trading is overwhelmingly bilateral, with buyers and sellers trading standard contracts by telephone or on electronic bulletin boards. Gas traders voluntarily report price and volume information to publishers such as Platts, which in turn report indexes based on representative prices for dozens of pricing points throughout the United States and Canada.

Two locations have emerged as particularly important trading hubs: AECO, in Alberta, Canada and Henry Hub, in Louisiana. These trading hubs are located near major producing regions in the Western Canadian Sedimentary Basin and Gulf of Mexico,

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[101] NEB (1995) *Price Convergence in North American Natural Gas Markets*, National Energy Board, Calgary, Alberta, Canada.

respectively.[102] Henry Hub, the delivery location for the NYMEX futures contracts, serves as a benchmark for the continental natural gas market.

NYMEX futures contracts

The New York Mercantile Exchange offers trading in natural gas futures contracts. A NYMEX contract is for 10,000 MMBtu delivered uniformly across a calendar month to Henry Hub. Prices are quoted in dollars per MMBtu. At any given time, 72 consecutive monthly contracts are open for trading, beginning with the next calendar month. NYMEX futures contracts are settled daily on a mark-to-market basis; all traders holding "open" positions either pay or receive funds ("margins") each day depending on the change in the settlement price from the previous day.

NYMEX futures trading is extremely liquid, especially in the early months, and the gas futures contract has become a closely watched barometer of market expectations for future price movements. NYMEX gas futures prices help discover the spot gas prices in a future delivery period via trading activities of futures buyers and sellers. Trading statistics from September 15, 2003 show open interest in the October 2003 contract of 51,389 contracts, representing over 510 trillion Btu. At $4.685/MMBtu, the open positions were worth a total of $2.4 billion. Actual trading volume that day was 27,325 contracts, or 27 trillion Btu. By comparison, monthly natural gas consumption for the

[102] NEB(2002) *Canadian Natural Gas Market, Dynamics and Pricing: An Update*. National Energy Board

United States is approximately 1,900 trillion Btu. Liquidity declines for delivery months that are further out in time, as demonstrated in Figure 67. However, the trading data show open positions worth $100 million for delivery months as late as March 2006, and $20 million through February 2007.

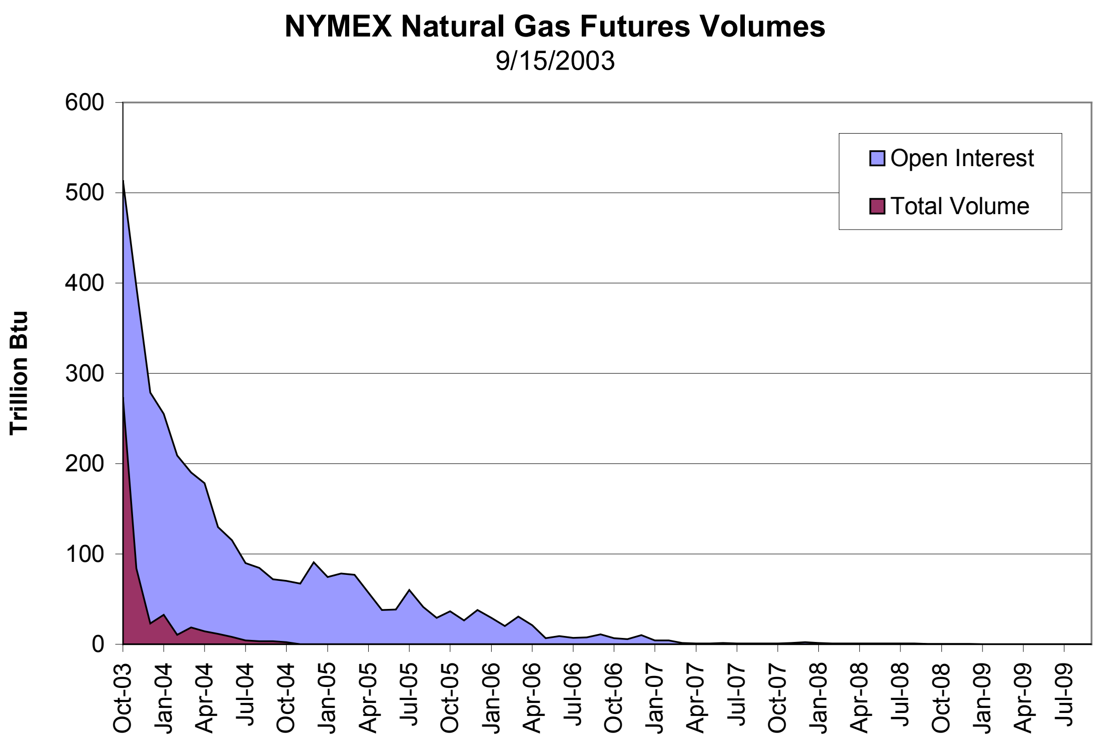

Figure 67: NYMEX trading data for 9/15/2003.
"Open Interest" refers to all open positions for that month's delivery, and "Total Volume" reflects volume traded on 9/15/2003. Trading is extremely liquid for the near months, less so for the far months.

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of Canada, Calgary, Alberta, Canada.

Basis trading

Traders typically link prices at different locations through "basis differentials." A basis differential is the difference in the market value of natural gas at two separate physical locations at the same point in time.[103] Basis differentials respond to temporary events such as localized shortages or surpluses of natural gas supply or reductions in pipeline capacity. They can also vary over time with the introduction of new pipeline or storage capacity, changes in production costs at various locations, or permanent demand shifts.

Forward basis differentials are traded as financial derivatives known as "basis swaps". The holder of one side of a basis swap agrees to pay the counterparty the difference between the spot prices at the two specified locations at the designated time. NYMEX offers clearing services and calculates settlement prices for forward natural gas basis swaps contracts between Henry Hub and a number of pricing points, including two California locations: PG&E Citygate and SoCal Gas. NYMEX forward basis swaps contracts are for 2,500 MMBtu, and are settled as the monthly bidweek spot price (as defined by a particular price index such as *Natural Gas Intelligence*) minus the final settlement price of a Henry Hub futures contract for the corresponding month.[104] NYMEX will clear trades for basis swaps up to 36 months out in time, although settlement prices are only calculated for those months in which traders hold open positions. Figure 68 shows basis swap prices for the two California locations as of September 15, 2003.

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[103] Allenergy.com, *Natural Gas Glossary*, http://www.allenergy.com/natural_gas/ngglossary.html
[104] New York Mercantile Exchange, http://www.nymex.com/jsp/markets/ng_oth_pgbdes.jsp

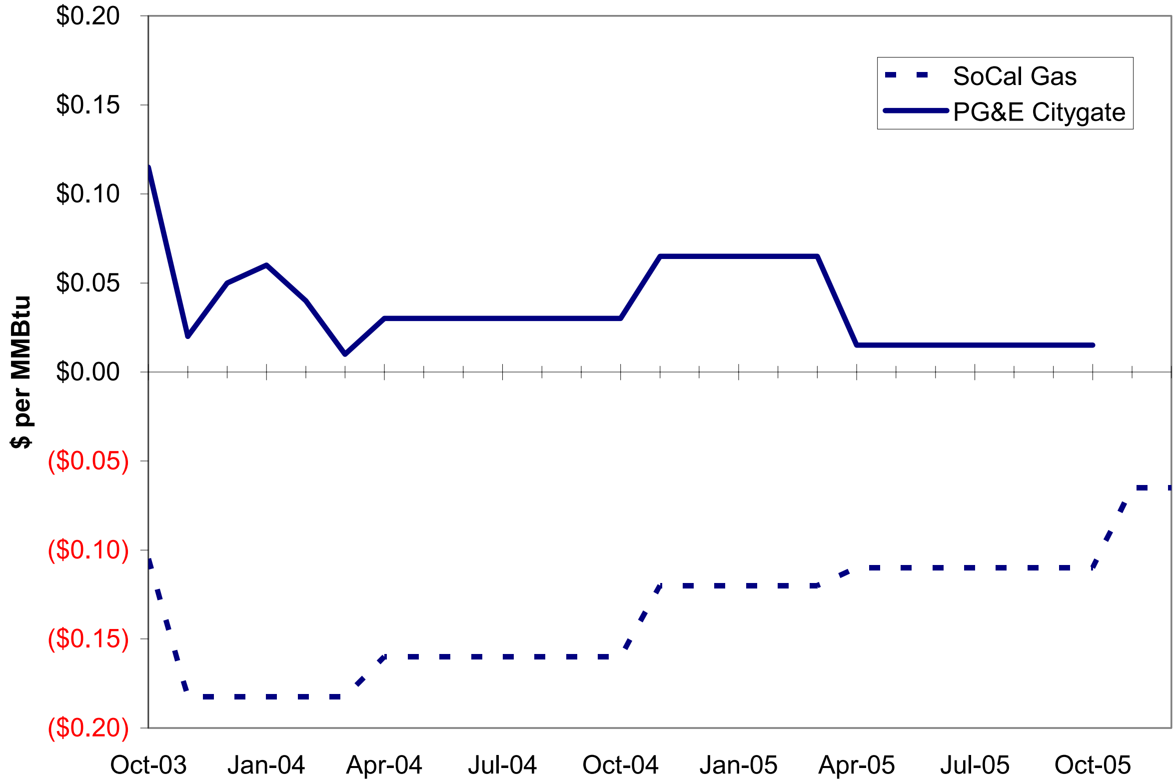

Figure 68: Settlement prices ($/MMBtu) of NYMEX basis swaps contracts on 09/15/03 for PG&E Citygate (October 2003 to October 2005) and SoCal Gas (October 2003 to December 2005).
Basis swaps contracts are settled as the Natural Gas Intelligence index price minus the final settlement price of the NYMEX Henry Hub futures contract. Source: New York Mercantile Exchange

2.8.2 California's natural gas supplies

California produces approximately 20 percent of its natural gas supply, primarily at locations in the Kern River valley. The remainder must be imported from outside the state, primarily from supply basins in Texas, New Mexico, Colorado, and western Canada. Figure 69 shows the major supply basins and interstate pipelines in the western United States and Canada.

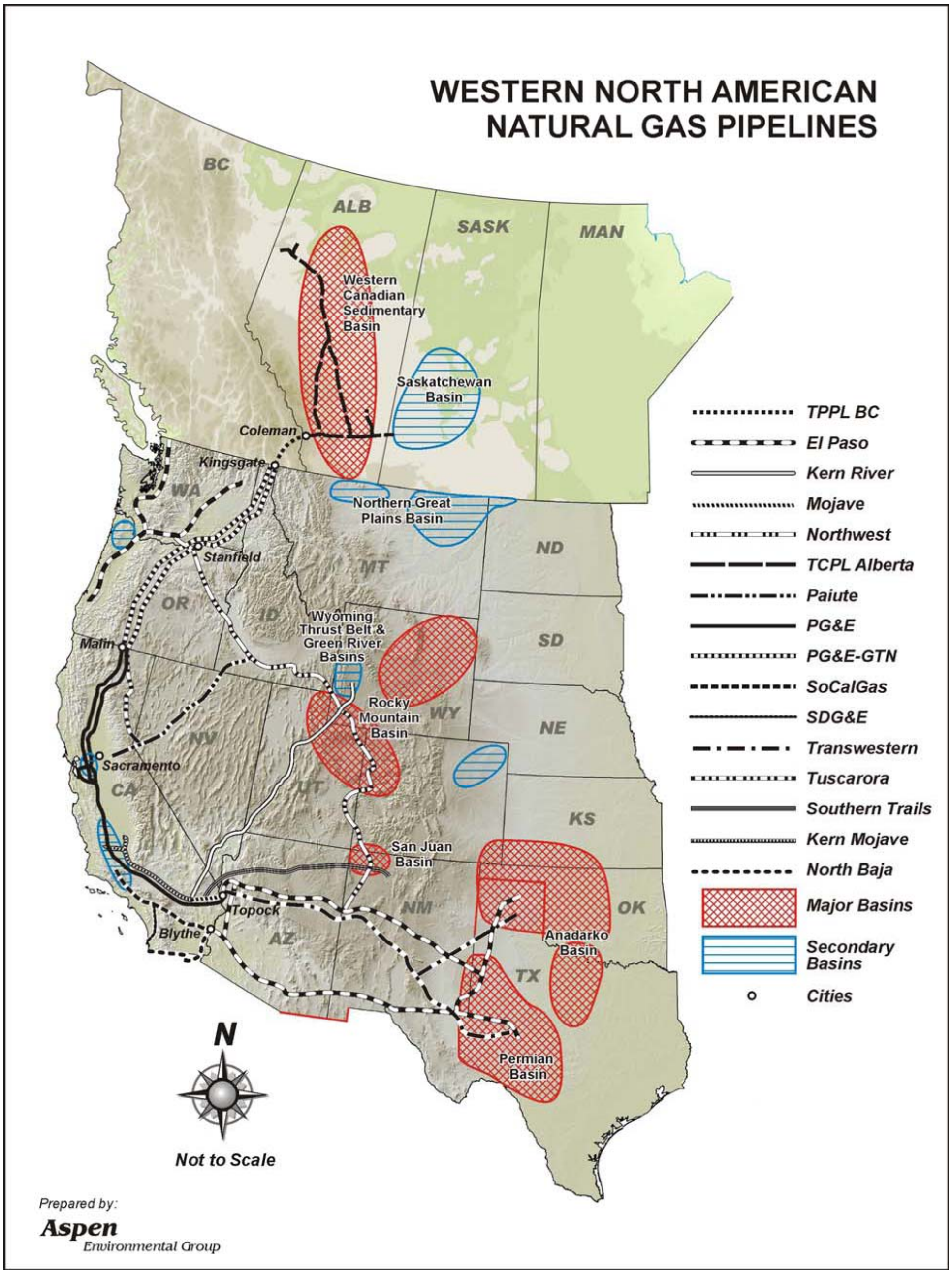

Figure 69: Natural-gas pipelines and supply basins in Western North America. Major supply basins serving California include the Western Canadian Sedimentary Basin, serving Northern California, the San Juan, Permian and Anadarko Basins, serving Southern California, and the Rocky Mountain Basin, serving both. Source: California Energy Commission, Natural Gas Market Assessment

Because of limited transport capacity inside California, natural gas supplies for northern and southern California have different origination points:

- Northern California is primarily served by Canadian gas transported through PG&E's Gas Transmission Northwest (GTN) pipeline, which connects with PG&E's California Gas Transmission (CGT) system at Malin, Oregon. Rocky Mountain supply basins in Colorado and Wyoming are a secondary source of northern California gas. Spot gas in northern California is traded at the "PG&E Citygate" pricing point, which refers to any number of points at which the CGT system interconnects with PG&E's local distribution system.

- Southern California gas originates primarily in the San Juan, Permian and Anadarko supply basins, and is transported to the California-Arizona border through of a network of pipelines that connect with Southern California Gas at either Topock, Arizona or Blythe, California. The recent expansion of the Kern River pipeline has provided a more direct route for low-priced Rocky Mountain supplies to reach southern California. The principle spot market for southern California is the SoCal Gas pricing point at the California-Arizona border.

Table 38 lists interstate pipelines serving California, and their 2003 maximum delivery capacities.

Table 38: Maximum Delivery Capacity of Interstate Pipelines Serving California[105]

Pipeline	MMcf/day
PG&E Gas Transmission Northwest	2,150
Kern River	1,750
Northern El Paso	1,680
Southern El Paso	1,210
Transwestern	1,210
All American	230
Questar So. Trails	80
Total	*8,310*

2.8.3 Price history, California and Henry Hub markets

Natural gas prices declined rapidly after price decontrol in 1985 and were at historic lows across the continent for much of the 1990s, including California. Figure 70 shows that prices did not exceed $3/MMBtu for any length of time until the beginning of the western energy crisis in spring of 2000. Prior to May 2000, small but positive basis differentials (generally under 20¢/MMBtu) existed between California locations and Henry Hub, indicating that gas was somewhat more expensive in California than in Louisiana. On average, northern California gas was slightly more expensive than southern California gas.

These price trends changed dramatically with the onset of the western energy crisis in mid-2000. While continental prices began to move upwards in May 2000, prices skyrocketed in California, leading to higher basis differentials. In mid-November 2000, prices on the West Coast spiked to unprecedented levels. SoCal Gas prices peaked at $50/MMBtu on December 9th, 2000, and averaged nearly $25/MMBtu for the month of

[105] California Energy Commission, Natural Gas Market Assessment

December 2000. Henry Hub prices also moved higher during that period, exceeding $10/MMBtu in late December, but basis differentials between Henry Hub and California remained extraordinarily high through June 2001.

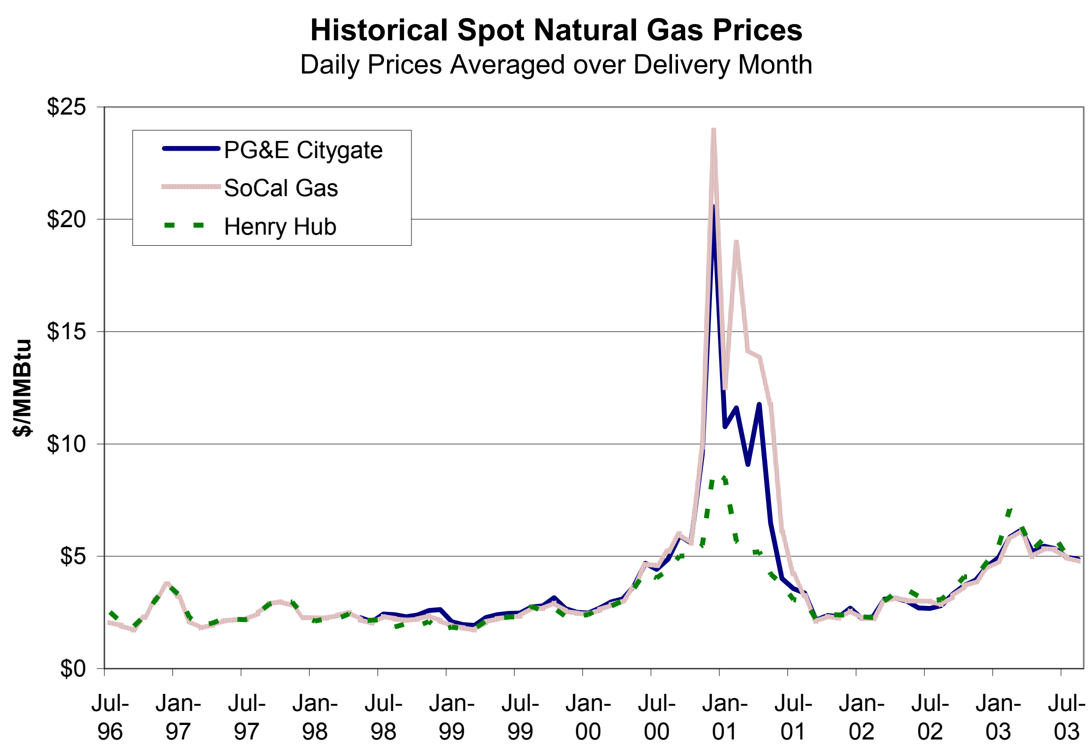

Figure 70: Spot natural gas prices (averaged over the delivery month) for July 1996 through July 2003.
California prices spiked to unprecedented levels in December 2000, and remained high for the first half of 2001.

At the end of the energy crisis in mid-2001, California prices retreated to historic levels below $3.00/MMBtu, and basis differentials to Henry Hub were very close to zero through the winter of 2001-02. Prices in all three markets began to rise again beginning in March 2002, and increased dramatically in 2003 with concerns about the adequacy of continental supplies. However, California prices increases lagged those at Henry Hub, leading to consistent negative basis differentials between March 2002 and September 2003.

2.8.4 E3's approach to forecasting avoided cost of natural gas commodity

E3's approach divides the 2004-2023 forecast time frame into three periods, defined by the availability of market data:

- **Period 1, January 2004 – December 2005.** During this period, in which NYMEX gas futures and basis swap prices are available, gas prices are forecast as the NYMEX futures prices for Henry Hub plus NYMEX basis swaps prices between Henry Hub and California locations. Basis swaps are positive in the near-term for PG&E and negative for SoCal Gas, resulting in PG&E commodity prices that are somewhat higher than SoCal Gas prices. Basis swap prices trend toward zero over the 2-year period.

- **Period 2, January 2006 – October 2009.** During this period, in which only NYMEX gas futures are traded, gas prices are forecast as the NYMEX futures prices plus estimated basis differentials between Henry Hub and California locations. Detailed in the appendices beginning on page 251 of this report, we provide an econometric analysis of daily spot price data finds that an unbiased estimate of the basis differential is not statistically different from zero. Hence, the forecast is simply the NYMEX futures prices.

- **Period 3, November 2009 and beyond.** No futures contracts are traded for this period. Hence, E3 relies on forecasts of long-term natural gas prices from the CEC. The CEC forecasts annual delivered energy prices by customer class for each of the three major California gas utilities. E3 translates these into monthly values using multipliers derived from the last of year of NYMEX futures trading. E3 also included in the model a 36-month transition period, during which prices are an interpolation between the price of the final NYMEX contract in Month 72 and the CEC forecast price in Month 108, ensuring no sudden price movement as the forecast moves to the long-term method.

E3's forecast takes a hybrid approach, combining a market-based forecast for the near-term, when futures contracts are traded, and a model-based forecast for the long-term when there is no futures trading. It differs from publicly available long-term forecasts from the CEC and EIA, which use cost-based, long-run equilibrium models driven by estimates of the future cost of finding, producing and transporting natural gas to arrive at a delivered cost of natural gas to various types of consumers.

Direct reliance on forecasts by the CEC or the federal Energy Information Administration, rather than basing the forecast on market data during the early years, would have the advantage of simplicity. However, long-term forecasts may be based on information that is already several months old by the time the forecast is made public. Figure 71 illustrates that long-term forecasts can quickly become out-of-date when major price movements occur. Both agencies forecast 2003 and 2004 natural gas prices below $4 per MMBtu, despite the fact that prices have been well above that level since

December 2002. Neither forecast appears to have taken account of events in 2003 that drove up short-term prices.

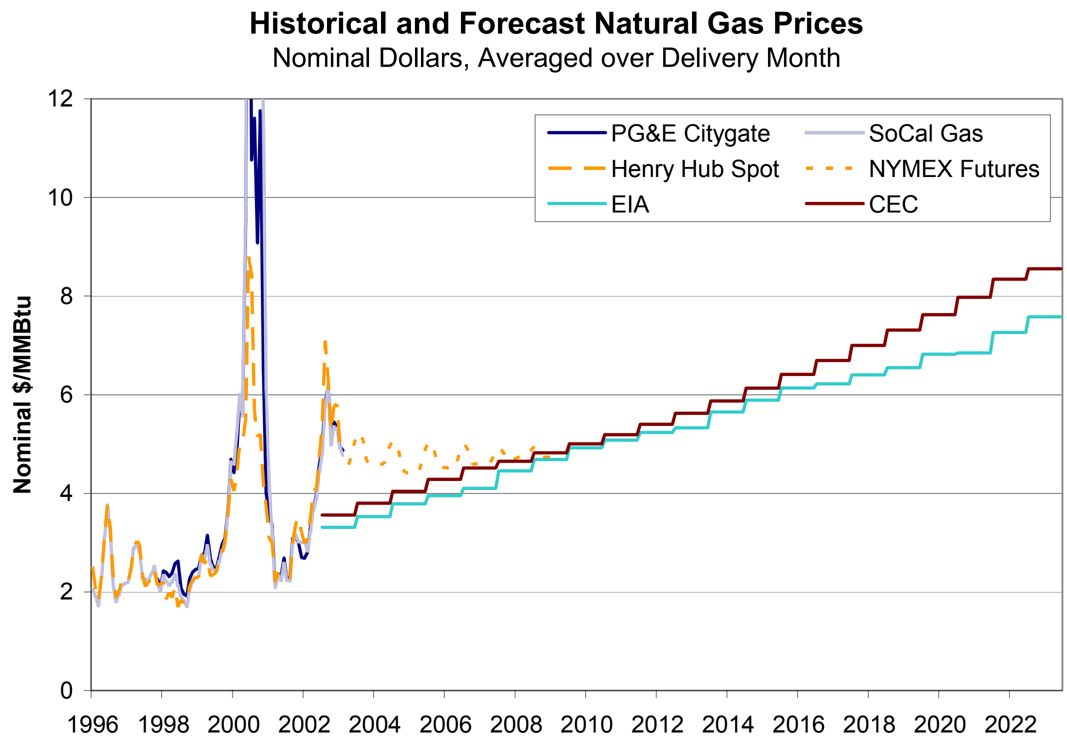

Figure 71: Historical and forecast natural gas prices.
Historical prices are daily spot market prices at PG&E Citygate, SoCal Gas and Henry Hub, averaged over the delivery month. The most recent CEC forecast was published August 8, 2003, but relied on April 8, 2003 model runs. The most recent EIA forecast was published January 9, 2003, relying on November 5, 2002 model runs.

Also visible in Figure 71 are the September 15, 2003 prices for NYMEX natural gas futures contracts, and historical spot market prices for Henry Hub. This comparison suggests that E3's approach provides a bridge between the near-term market-based forecast driven by futures price data and the long-term model-based forecast driven by long-term demand and supply developments.

Avoided natural gas transportation costs

Avoided natural gas costs differ by customer type: core customers of local natural gas distribution companies (LDCs) as opposed to electric generators. Both customer types pay for the same natural gas commodity cost but have different avoided transportation costs.

Avoidable marginal distribution costs for core customers

Avoided distribution costs reflect avoided or deferred upgrades to the distribution systems of each of the three major LDCs in California. These costs were described earlier in Section 2.5 of this report.

Transportation charges for electric generators

Avoided natural gas costs for electric generators serve as inputs to electricity avoided costs. Electric generators in California purchase natural gas directly from the wholesale market, paying only transportation charges to LDCs. Because generators are not core customers, the appropriate measure of avoidable transportation charges is the applicable LDC tariff rate. The tariff rates we used in our analysis are listed in Table 39. LDC tariff rates are added to the natural commodity forecast for first 72 months of the forecast period, when prices are based on NYMEX futures. After 2009, the CEC forecasts delivered prices to electric generators, including LDC transportation charges.

Table 39: SoCal Gas and PG&E Gas Transportation Charges for Electric Generators

SoCal Gas Tariff Rates

Delivery to Electric Generators (cents per therm)		
GT-F5	3 million or more therms per year	2.700
GT-SUR	Customer-procured gas franchise fee surcharge	0.470
	Total charge delivered to burner tip:	*3.170*

http://www.socalgas.com/regulatory/tariffs/tariffs_rates.shtml

PG&E Gas Tariff Rates

Delivery to Electric Generators (cents per therm)		
G-EG	Gas Transportation Service to Electric Generation	2.460
GT-SUR	Customer-procured gas franchise fee surcharge	0.780
	Total charge delivered to burner tip:	*3.240*

http://www.pge.com/customer_services/business/tariffs/#GRS

3.0 Aggregate Base Case Results

3.1 Comparison with Existing Avoided Cost

In this section we compare the new avoided cost values developed in this study with the existing values currently used for evaluation of Public Goods Charge (PGC) funded programs as specified in the *Policy Manual*.[106] Since the new costs are disaggregated by time, utility, planning area, climate zone and voltage level (for electricity), this comparison is done by annual average, time-of-use (TOU) period, and hour (month for natural gas). We have also included in this section comparisons of both the new and existing avoided costs for three electric and two natural gas efficiency measures to illustrate the difference the application of the new avoided costs versus the existing avoided costs in overall program cost-effectiveness evaluation.

[106] We have included Chapter 4 of the *Energy Efficiency Policy Manual* in the Appendix, which provides the existing values, and describes each of the inputs used to derive them.

3.2 Existing Avoided Cost Values

The existing cost savings are provided in the *Policy Manual* on an annual basis and broken into three components (generation, T&D, and environment). We display the existing electric avoided costs in Figure 72. The vertical axis shows the avoided cost in nominal $/MWh. The avoided cost values range from $62 to $126/MWh over the 22-year forecast period. If the 2002 and 2003 avoided costs are not included (2002 was abnormally high in the aftermath the California energy crisis) then the 20-year levelized value for 2004-2023 is about $80/MWh, which we show as a thick horizontal line. We will use this $80/MWh levelized existing value for comparison with the new avoided costs throughout the next section. For consistency, the units have been converted to $/MWh from $/kWh provided in the *Policy Manual*.

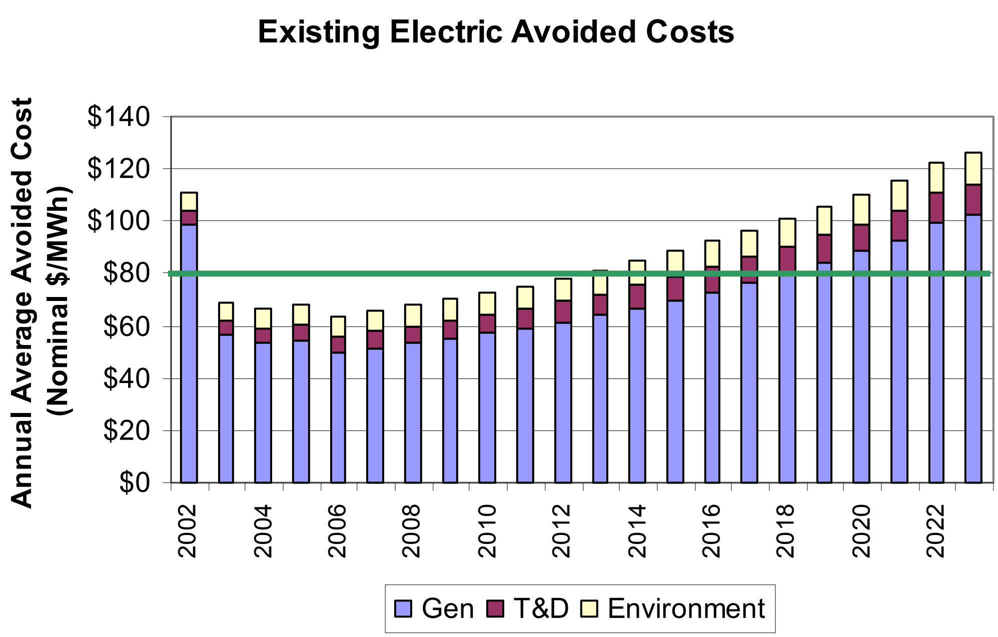

Figure 72: Existing total electric avoided costs by year (with levelized value)

The existing electric avoided cost values were computed as an average avoided cost for each year in the forecast horizon, with inputs from a number of sources. The generation component was based on a CEC forecast completed in August 2000, with updates from an October 25, 2000 ALJ ruling.[107] The updates increased the prices in the period 2002-2010 over the base CEC forecast and incorporated an "on-peak" multiplier. The T&D avoided costs and the environmental externalities were based on Commission adopted values in Resolution E-3592.[108] The August 2003 update of the *Policy Manual* (Version II) extended the forecast from 2021 to 2023 by escalating the individual components by their average growth rates over the previous five years.

We display the current natural gas avoided cost values in Figure 73. Annual average avoided costs are reported in the *Policy Manual* for each forecast year for natural gas commodity, T&D, and environmental value streams. The vertical axis shows the avoided cost in nominal $/therm. The avoided costs range from a savings of approximately $0.42 to $0.81 savings per therm of reduced gas consumption. We also calculated the levelized natural gas avoided cost over 20 years (2004-2023) which is approximately $0.54/therm and is shown as a horizontal line on the Figure 73.

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[107] October 25, 2000 ALJ Ruling on PY2001 planning in A.99-09-049
[108] California Public Utilities Resolution E-3592, April 1, 1999

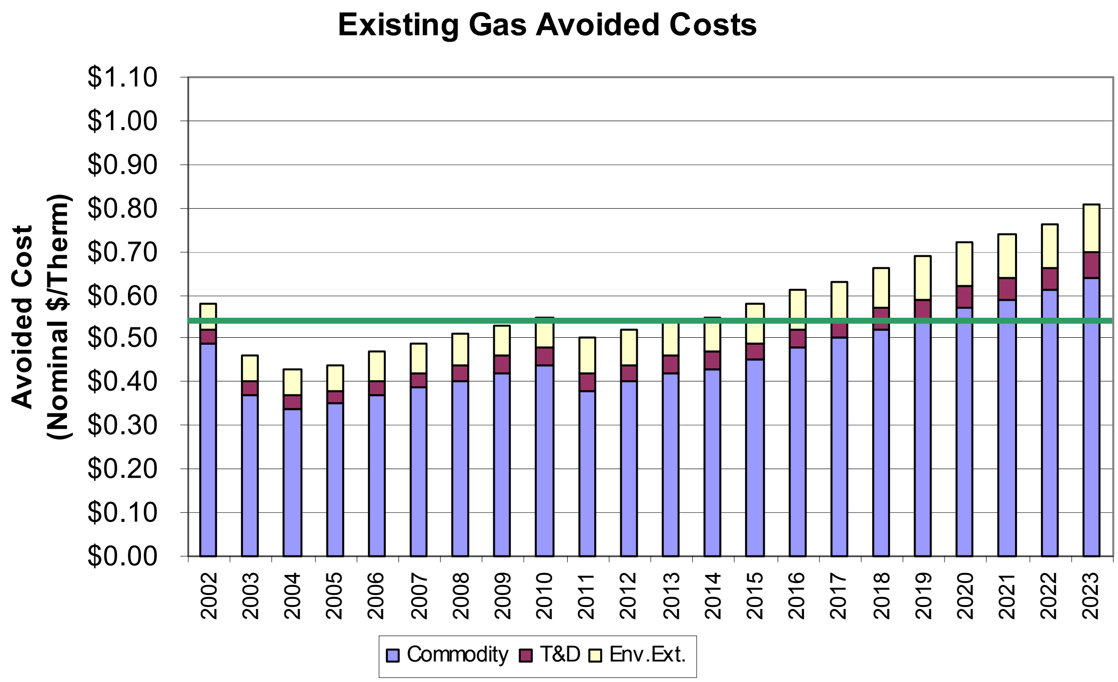

Figure 73: Existing gas avoided costs by year (with levelized value for 2004-2023)

Similar to the electric conservation measures, the existing natural gas avoided costs represent forecasted average annual avoided costs of commodity, T&D, and environmental value streams for each year of the forecast. The existing natural gas commodity forecast is based on the CEC's August 2000 base case price forecast for electric generation. The T&D costs are the weighted average of the PG&E, SDG&E, and SoCal Gas T&D costs from their PY2000 annual reports. The environmental values are based upon the Commission values adopted in Resolution E-3592. The CPUC extended the original forecast from 2021 to 2023 by escalating the individual components by their average growth rates over the previous five years.

3.3 Comparison of New and Existing Avoided Costs

3.3.1 Electric Avoided Cost Comparison

Whereas the CPUC's existing avoided costs are annual, statewide forecasts, the new forecast avoided costs vary by both area and time. In fact, for electricity, we have calculated the avoided costs by hour for each year for the 16 climate zones, 24 electric utility planning divisions, and 3 service voltage levels (transmission and primary and secondary distribution). Figure 74 shows the approximate range of the new levelized avoided cost values by planning division and service voltage level for 2004-2021 compared to the CPUC's existing values.[109] The figure shows that most of the new primary and secondary service voltage area- and time-specific avoided costs (in 2004 dollars) fall between \$70 and \$75/MWh. However, as a result of our disaggregation of costs, the new avoided costs at the transmission service level do not include distribution costs; therefore, they range from \$63/MWh for SDG&E to \$65/MWh for PG&E and SCE's service territories. The corresponding value for the CPUC's existing all-in levelized forecast is about \$80/MWh, which is higher than all of the new forecast values and about 10% higher than the mode of the new primary and secondary avoided costs.

[109] For comparison purposes, we have excluded the 2002-2003 data from the CPUC's existing forecast because they do not overlap with the new forecast period and the 2002 data is abnormally high due to the California energy crisis. To be consistent, we have also removed 2022-2023 data from the new forecast for comparison.

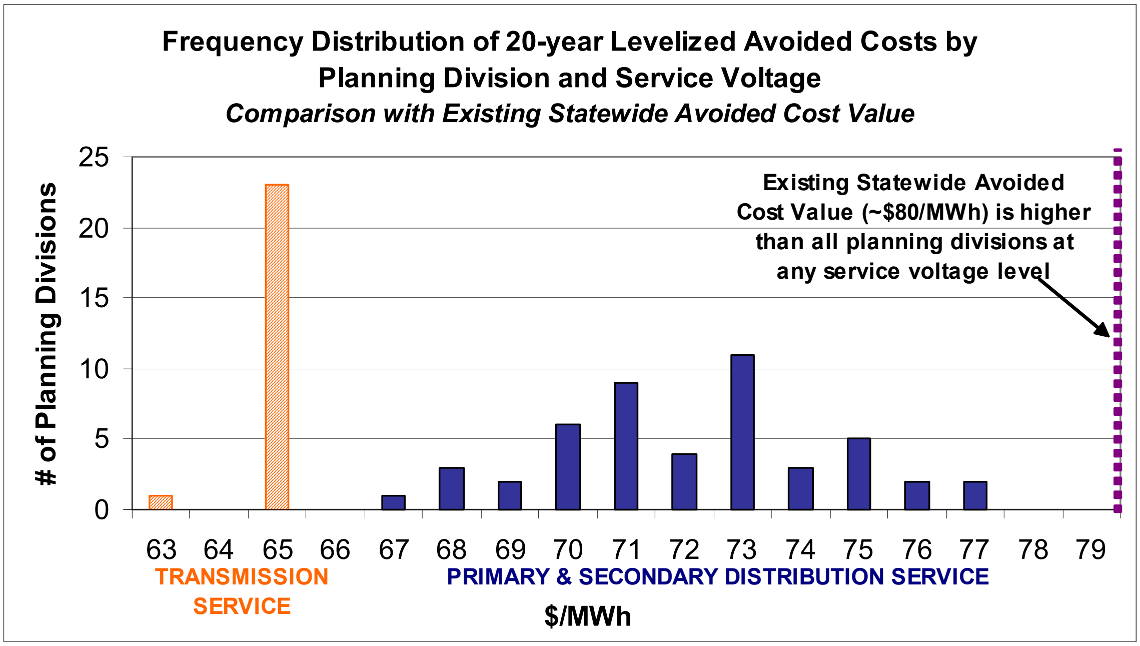

Figure 74: Histogram of existing and new levelized electric avoided costs (2004-2021)

Figure 75 compares our new forecast of annual average electric avoided costs for the San Jose Planning Division (secondary service voltage) to the existing avoided costs. We have chosen San Jose to illustrate the comparison because its levelized avoided cost falls into the $73/MWh bracket, the mode of the primary and secondary distribution of Figure 74. Although the costing data and methodologies are substantially different, our new annual forecast for San Jose is remarkably close to the CPUC's existing forecast for the same period, even though the CPUC prepared its forecast immediately following the California Energy Crisis.[110] One of the main differences is that the CPUC's existing forecast grows at a faster rate than our new forecast over the long run. The escalation of the new long run avoided costs beyond 2008 is driven by the increase in natural gas costs, which ranges from 3% to 5% per year.

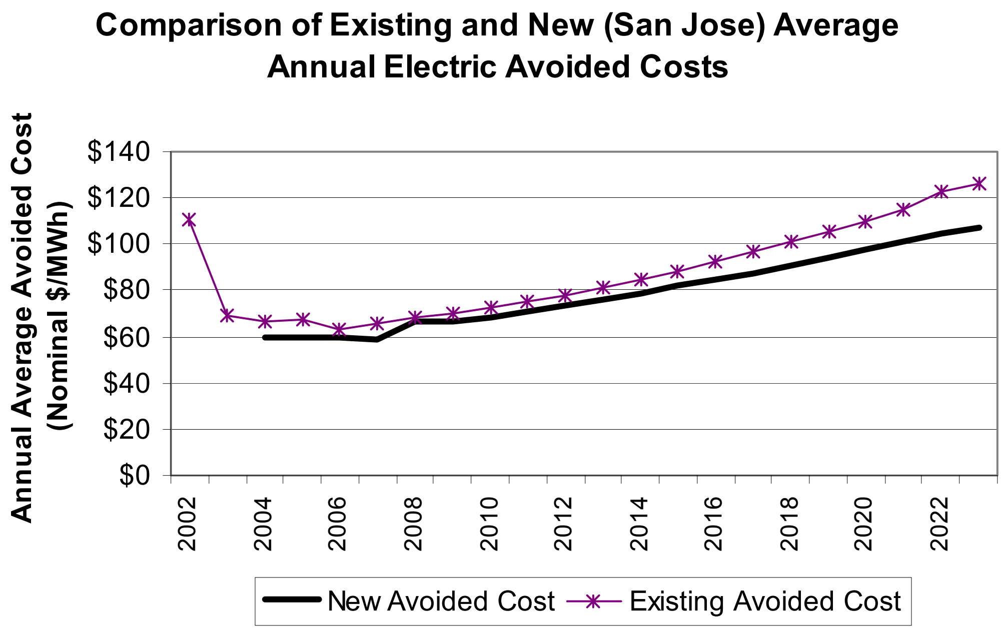

Figure 75: Comparison of existing and new electric avoided costs (new costs are for San Jose, Climate Zone 4, secondary voltage)

We show the new levelized avoided costs by time-of-use (TOU) period in Figure 76. Again, we used the PG&E's San Jose Planning Division as an example.[111] For comparison, the existing 20-year levelized avoided costs of approximately $80/MWh is shown as a solid horizontal line on the graph. The summer on-peak avoided costs are approximately $140/MWh, which is significantly higher than the existing avoided costs. The partial peak periods have approximately the same avoided cost as the existing, whereas the off-peak periods have significantly lower avoided costs than the existing values.

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[110] The CPUC prepared the existing values for 2004-2021 in October 2001. In August 2003, it issued an update that extended the first forecast out through 2023.

[111] The PG&E time-of-use period definitions are used in this example. The summer months are from May through October. Summer peak (11am to 6pm), summer partial peak (7am to 11am, 6pm to 8pm), summer off-peak (other summer hours), winter partial peak (7am to 8pm), and winter off-peak (other winter hours).

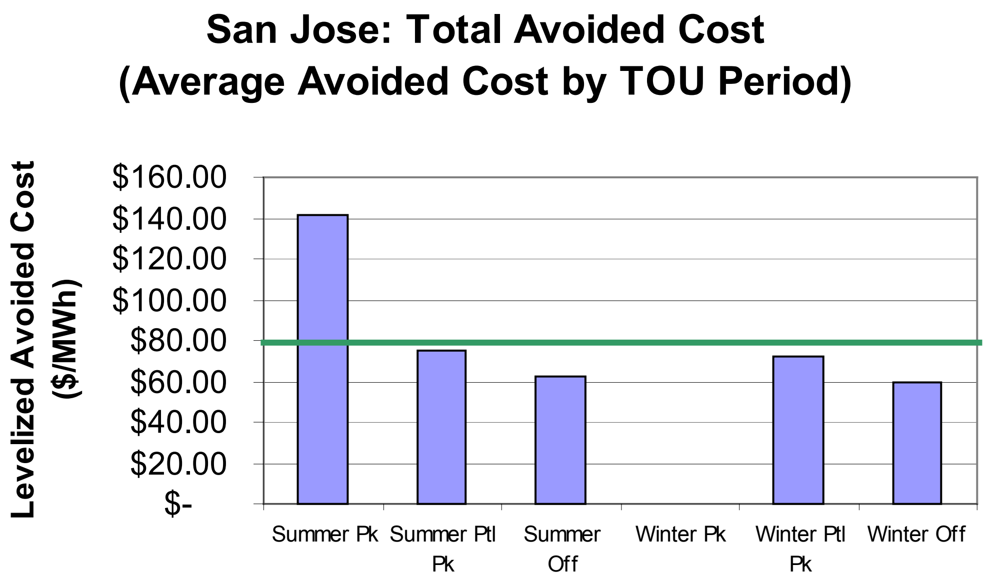

Figure 76: New total electric avoided cost by TOU period for San Jose Planning Division (Climate Zone 4, secondary voltage)

The relatively high avoided costs seen in Figure 76 during the summer peak period are due to both higher forecast commodity prices and the allocation of the T&D costs in Climate Zone 4 (portions of the San Jose, Los Padres, De Anza and Central Coast planning divisions). In Figure 77, we show the new avoided costs in two charts. In the chart on the left, the commodity and environmental components are shown by TOU period in $/MWh, in the chart on the right, the T&D avoided costs are shown by TOU period in $/kW-year. The existing levelized values of these components are shown in the both charts as a thick horizontal line. Looking at the commodity and environmental graph, the new avoided costs are higher than the existing avoided costs in the on-peak period and about the same in the summer and winter partial peak periods. The new T&D avoided costs are almost entirely allocated to the summer peak period for Climate Zone

4, but in total they are considerably lower than the existing T&D avoided costs. It becomes clearer then when looking at these graphs that the existing T&D avoided costs which are based on a statewide average do not reflect the same level of disaggregation as the new avoided costs, which allow us to identify differences by TOU periods.

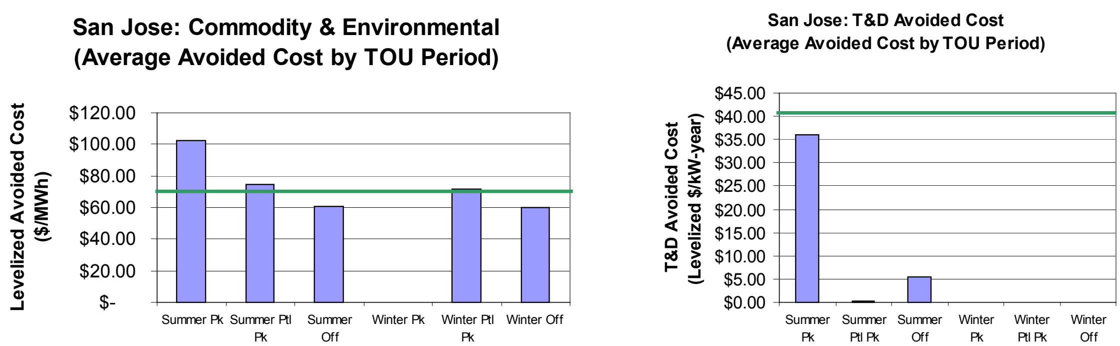

Figure 77: New avoided cost by TOU Period (commodity and Environment $/MWh, T&D avoided cost $/kW-year) for San Jose

In Figure 78, we further disaggregate the new avoided costs to hour and month for the San Jose example. Figure 78 shows the levelized electric avoided costs in San Jose by month and hour.[112] The vertical axis in Figure 78 shows the total avoided cost in levelized $/MWh. During the highest cost period for San Jose, the total avoided costs peak at approximately $225/MWh from late July through September, with the value above $140/MWh due to the allocation of T&D costs to peak hours.

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[112] The spreadsheet produces a database that includes estimates of avoided costs for each hour of the year for the next 20 years. This set of data is maintained for the CEC defined climate zones.

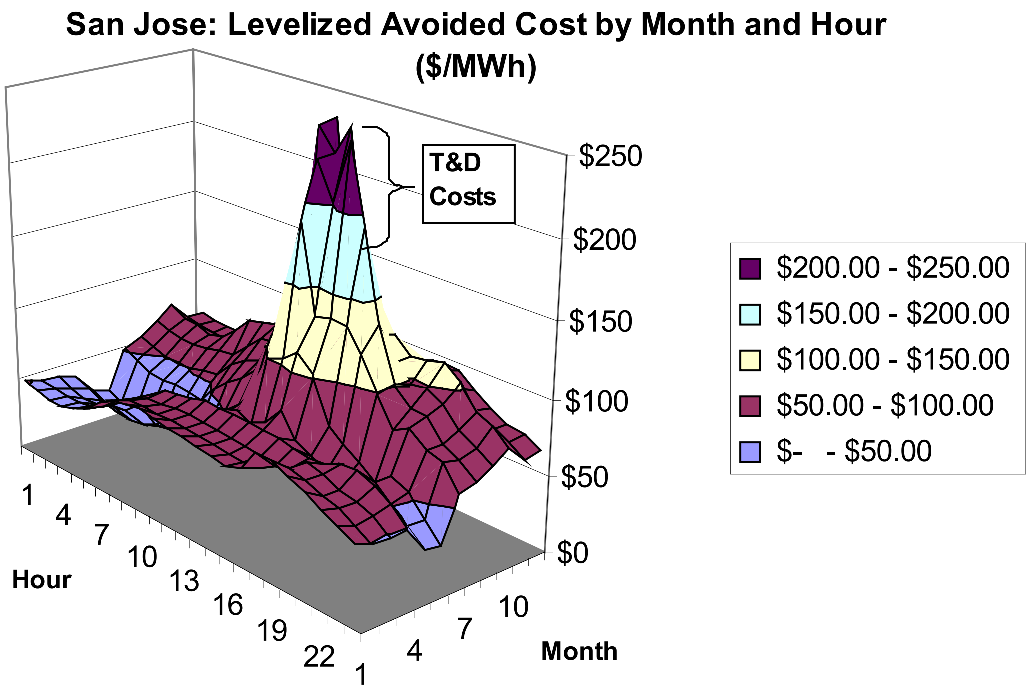


Figure 78: Electric avoided cost by hour and month for San Jose

The same hourly avoided costs by month are shown in topographical view in Figure 79. In this figure, we can identify the specific hours and months of the summer peak values. The highest avoided costs occur from late morning to mid-afternoon in late July, August and early September. Late mornings through early evenings of June through October also have avoided costs averaging that exceed $100/MWh. The early morning hours of January through July have costs averaging less than $50/MWh.

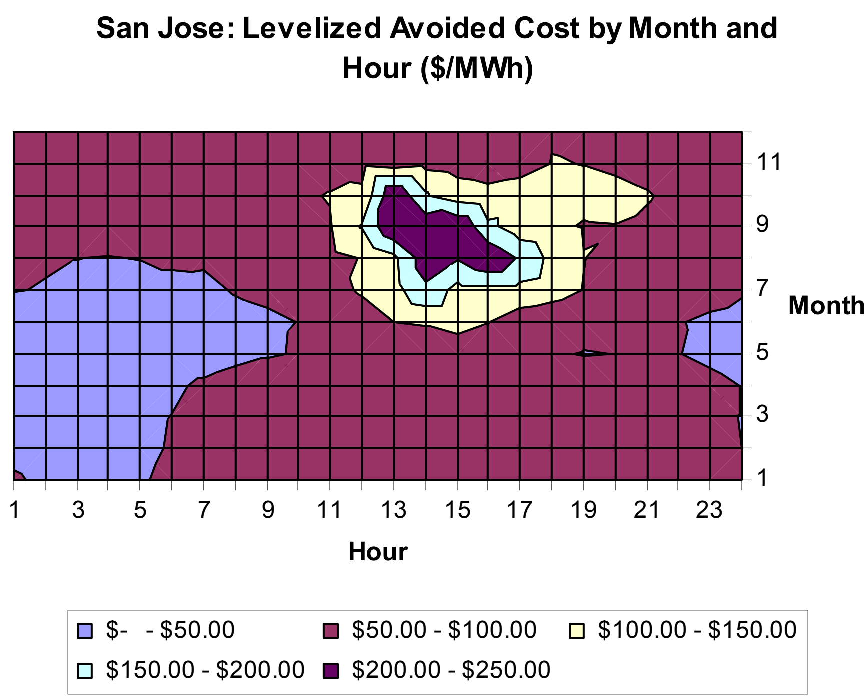
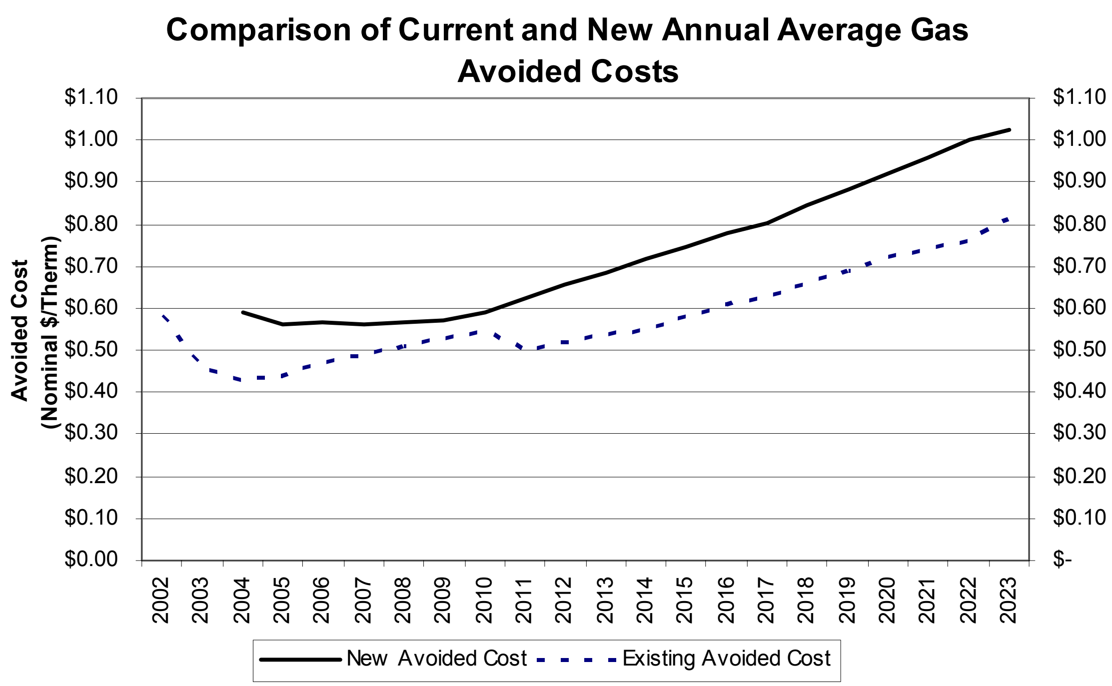


Figure 79: Total avoided cost by hour and month (topographical view) for PG&E's San Jose Planning Division

3.3.2 Gas Avoided Cost Comparison

In Figure 80,we show a comparison between the existing and new natural gas avoided costs. The vertical axis shows the gas avoided costs in $/therm. The bar charts in the figure are the sum of the existing commodity, T&D, and environmental externality component values specified in the *Policy Manual*. The line in this graph represents the forecasted new gas avoided costs.[113] Clearly, the new gas avoided costs have significantly higher annual average avoided costs than the existing natural gas avoided costs in the *Policy Manual*. The increase is approximately $0.08 to $0.15/therm from 2004 through 2010, and $0.15 to $0.20/therm after 2011.



[113] The new avoided cost example is based on SoCal gas core commercial customer with a large uncontrolled emissions boiler. However, the comparison of annual average appears the same for each gas segment.

Figure 80: Comparison of existing and new total gas avoided cost. New avoided costs based on SoCal commercial customer, large boiler, uncontrolled emissions

In Figure 81, we compare the levelized avoided costs by month. The vertical axis shows the levelized avoided costs in \$/therm. The flat horizontal line of \$0.54/therm is the 20-year levelized value of the existing avoided costs. The higher, curved line represents the monthly levelized shape of the new avoided costs. We allocated all the T&D costs in the new avoided costs to the winter period (November through March). In combination with the higher commodity costs in the winter months, the new avoided costs are about \$0.22/therm higher than the current annual average savings values. In the summer months, the new avoided costs are approximately \$0.06/therm higher.

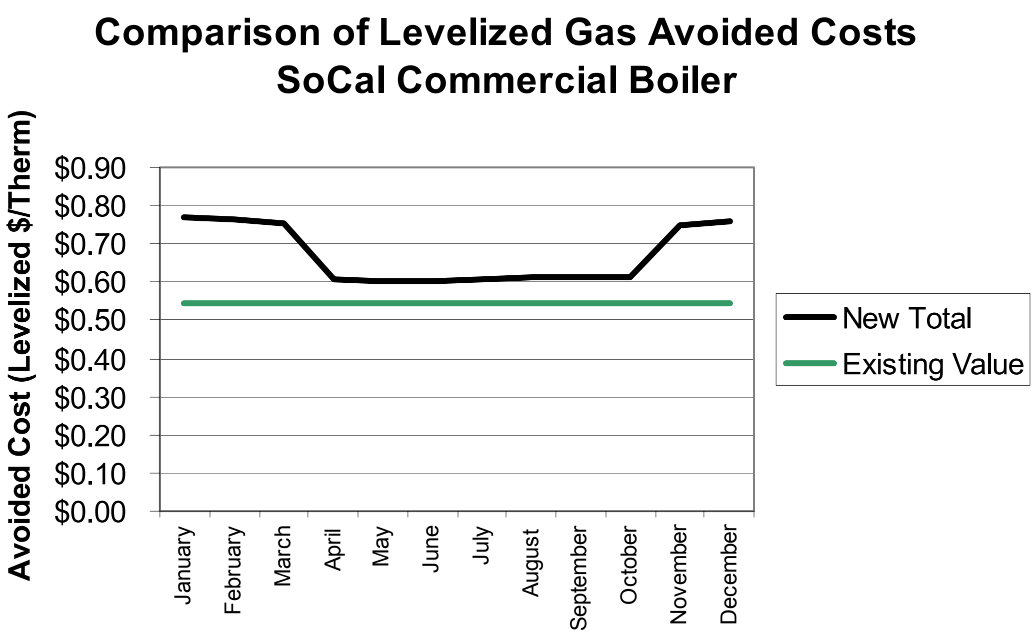


Figure 81: Comparison of levelized gas avoided cost by month

Finally, in Figure 82, we show the new gas avoided costs by month and year through the forecast period 2004 to 2023. In the early years of the forecast, the avoided costs vary from \$0.52 to \$0.73/therm depending on the season and increase to \$0.94 to \$1.15/therm in 2023. Each year in the forecast has the same basic monthly allocation.

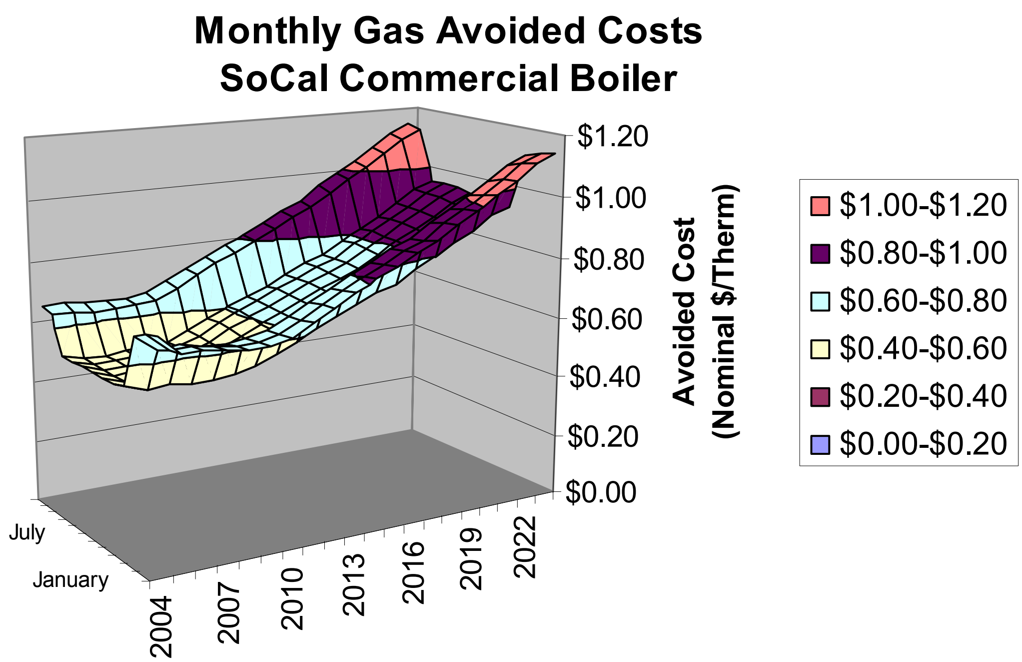


Figure 82: Gas avoided costs by month and year for SoCal Gas commercial customer, large boiler, uncontrolled emissions

3.4 Evaluation of Example Electric and Gas Measure Results

In this section, we compare the difference in value of conservation for different electric and gas measures using the existing and new avoided costs. While not a exhaustive comparison, we illustrate the difference in three electric measures and two natural gas measures to provide a range of potential impacts. In the new avoided costs, we disaggregated by time, which results in those measures that save more energy during peak periods having significantly more value than those that save energy in the off-peak periods compared to the existing costs. We compared multiple measures to show how the new avoided costs account for differentiation in both time of year and time of day, a difference which would not be observed when using the existing avoided cost values.

In Figure 83, we compare the results for three example electricity efficiency measures including an air conditioning program, an outdoor lighting program, and a refrigeration program. For each measure, we show the weighted average avoided cost for the existing and new avoided cost value. All measures are expected to provide savings for 16 years, beginning in 2004. The air conditioning measure (upgrade of a residential A/C unit from 12 to 13 seasonal energy effiency rating or SEER) has an avoided cost savings of $138/MWh with the new avoided costs as compared to a savings of approximately $78/MWh using the existing avoided costs. The large differential is due to the fact that the majority of the savings in an A/C upgrade occurs during the summer peak period when the value is highest. In contrast, the value for outdoor lighting efficiency drops when applying the new avoided costs from $78/MWh to approximately $60/MWh because outdoor lighting programs target off-peak hours. Finally, refrigeration, which is traditionally assumed to have a flat energy savings profile, remains about the same under both sets of avoided cost.

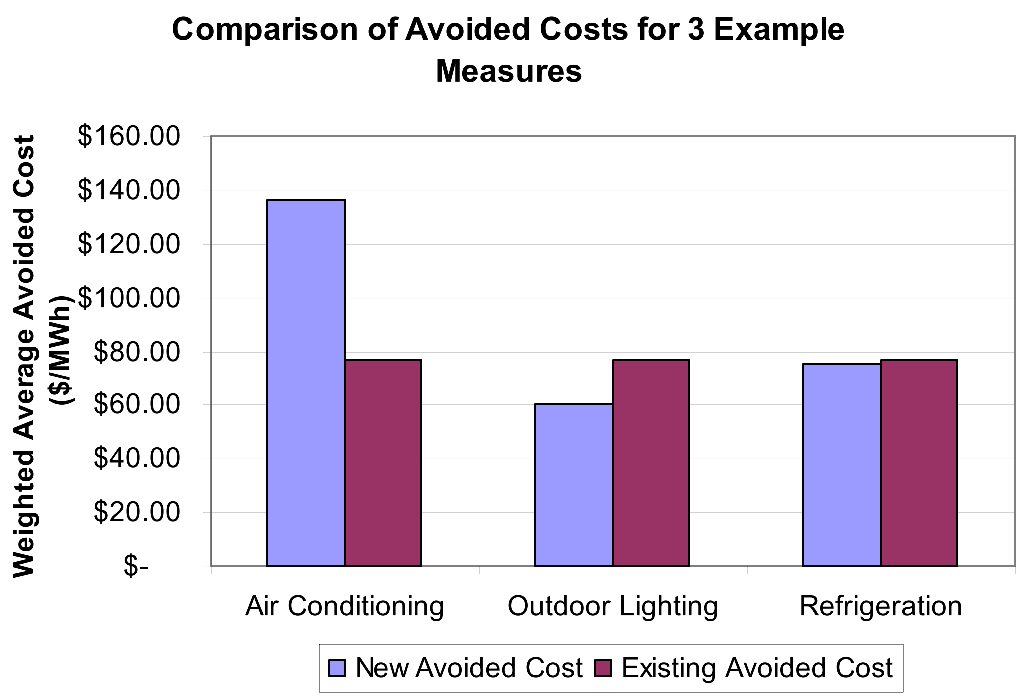


Figure 83: Comparison of new and existing electric results by measure for PG&E Climate Zone 12, secondary voltage

In Figure 84, we show a comparison of natural gas savings for two measures (heating and boiler efficiency) under the existing and new avoided cost values using a SoCal Gas commercial customer. The vertical axis shows the weighted average savings in $/therm over a 16 year period beginning in 2004. For heating conservation, which is assumed to save energy only during the winter months, the weighted average avoided cost is approximately $0.72/therm with the new avoided costs. This is significantly greater than the $0.51/therm savings this measure would receive with the existing avoided costs. The differential between new and existing avoided cost for boiler improvements is not as large since the measure will save energy all year.

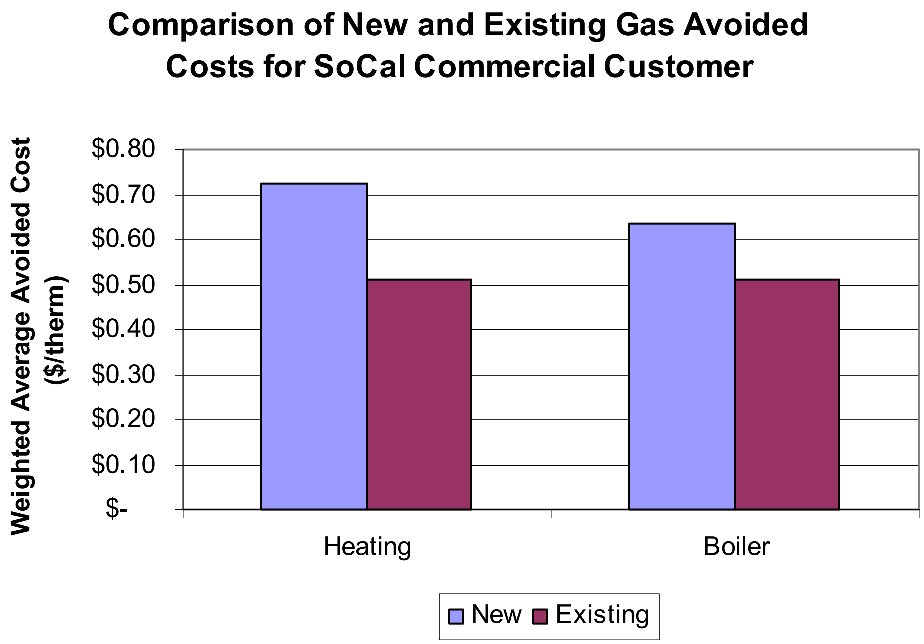


Figure 84: Comparison of new and existing gas results by measure for SoCal commercial customer

3.5 Summary of Comparison

In summary, comparison of the new and existing electric avoided costs shows that average annual electric avoided costs are similar, but that disaggregation to hour provides significantly higher benefits for conservation measures implemented during the summer peak period. In comparing existing and new natural gas avoided costs we see that the annual average of the new avoided costs are significantly higher, particularly in the winter months when commodity prices is higher and T&D is constrained. In both cases, conservation measures that reduce energy consumption during the peak periods (for example, cooling for electric, or heating for gas) receive significantly more value. In the case of the electric avoided costs, efficiency measures that reduce energy in the off-peak periods receive less value under the new avoided costs.

4.0 Dispatchable Resources & Scenario/Stress Case Analysis

4.1 Avoided Costs of Dispatchable Resources

This section describes the methodology for assessing the value of dispatchable load programs. These programs differ from energy efficiency programs that reduce load without a utility's active involvement. A dispatchable load program typically gives a utility the right, but not the obligation, to curtail a customer's load under agreed-upon circumstances.[114] The utility's right is defined by program parameters such as advance notice requirement, maximum operation frequency per month or year, and maximum duration per operation. Two examples of an interruptible/curtailable load program are:

- PG&E's non-domestic interruptible service under Schedule A-T (CPUC Sheet No. 11862-E, effective May 1, 1992) that applies to non-domestic customers with demand below 500 kW. PG&E pays $3.2/kW-month in May-September for the right to curtail a participating customer's load during 12:30-22:30 in May 1 – September 30.

- PG&E's E-20 non-firm service (CPUC Sheet 20738-E, effective October 1, 2003) that applies to commercial/industry/general service customers with demand of 1,000 kW or more. The secondary distribution non-firm service has a summer peak demand charge of $5.85/kW-month, summer part-peak $3.20/kW-month and a winter-part-peak demand charge of $3.15/kW-month, less than the firm service's corresponding

[114] Woo, C.K. (1990) "Efficient Electricity Pricing with Self-Rationing," *Journal of Regulatory Economics*, 2:1, 69-81; and Orans, R., C.K. Woo and C. Greenwell (1994)

demand charges of $13.35/kW-month, $3.70/kW-month and $3.65/kW-month. The demand charge discounts give PG&E the right to curtail, with 30-minute notice, a non-firm service customer's load under the following conditions (CPUC Sheet No. 18867-E, effective May 7, 2002): (a) no more than once a day, 40 hours per month, four times per week, and 30 times per year; (b) maximum duration of 6 hours per curtailment; and (c) maximum of 100 curtailment hours per year.

Dispatchable programs differ from non-dispatchable programs in that the utility can select the hours in which the load reduction occurs. Since the utility would select hours with the highest avoided costs, dispatchable programs should have a higher value than non-dispatchable programs. Dispatchable program value accrues due to the following factors:

1. **Avoided energy purchases.** Dispatchable programs can reduce energy purchases during high-price hours. This value depends on the energy prices during hours of curtailment and the number of dispatchable hours available.

2. **Deferred transmission and distribution investment.** Dispatchable programs can also defer the need for transmission and distribution system (T&D) investment. The deferral value depends on the T&D avoided costs, which vary by time, location and the number of dispatchable hours available.

Designing Profitable Rate Options Using Area- and Time-Specific Costs, Report No. TR-104375, Electric Power Research Institute.

3. **Improved allocation of limited capacity during an energy supply shortage.** A dispatchable program with voluntary participation improves the allocation of limited capacity during a shortage. Customers with relatively low value of service join the program and receive a payment (bill discount) from the utility that exceeds their expected outage costs. Customers with relatively high value of service remain on firm service and absorb program costs, which are less than their expected outage costs. In the event of a shortage, low-value customers are curtailed, helping to continue firm service to high-value customers. The program's net gain is the difference between (a) average expected outage cost under random rationing, and (b) expected outage cost of low-value customers selecting dispatchable programs. To be conservative, E3's evaluation of program value ignores this net gain.

E3's approach to assessing the value of a dispatchable program is to select the highest-cost hours given user-specified inputs such as energy strike price and maximum dispatch hours per day, month and year. Hourly avoided costs include energy, ancillary services and losses, emissions, and T&D avoided costs. Dispatching a program during the highest-cost hours yields the program's highest possible value, because it assumes perfect foresight and customer compliance.[115]

E3 also provides users the opportunity to replace E3's forecast of the annual average energy avoided cost with an alternative price scenario in the years prior to resource

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[115] The assumption of perfect foresight is not totally unreasonable because a utility can forecast day-of shortage caused by weather-driven load spikes with a very high degree of accuracy. The assumption of

balance. Addition of this feature stems from the recognition that actual electricity prices can be different from E3's baseline forecast. Combined with the fact that utilities are necessarily uncertain about the quantity of load they will have to serve in any given hour, this leads to potential volatility in the utility's cost of serving load. This effect is exacerbated by the high degree of correlation between high-price and high-demand hours. Dispatchable programs provide an additional tool that utilities can use to manage this volatility.

E3 develops alternative price scenarios using historic market price data, adjusted for the effects of the electricity crisis. Because it is unclear whether market data stemming from the crisis period can predict future price volatility, E3 does not assign probabilities to the scenarios. Instead, the avoided cost model allows users to select probabilities for each of four pre-populated scenarios, plus a custom scenario developed from user-specified inputs for natural gas prices and Western Electricity Coordinating Council (WECC) hydroelectric output.

4.2 Selecting Dispatch Hours

Most dispatchable programs are available for only a limited number of hours per year. Thus, calculating a dispatchable program's avoided costs requires determining the program's optimal dispatch pattern. E3's avoided cost spreadsheet model accepts the following user inputs:

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compliance is driven by the high non-compliance penalty (e.g., \$8.4 per non-complied kWh in PG&E's Schedule E-20 for non-firm service (CPUC Sheet No. 20737, effective October 1, 2003)).

- Utility, climate zone and planning area.

- Number of hours per dispatch. The model assumes that a program can be dispatched once per day for a fixed number of hours. For a program with four daily dispatch hours, the model will select the four consecutive hours within the day with the highest average avoided cost.

- Number of dispatches per month. This parameter constrains program operation. For example, a program that is dispatched for four hours and is available for ten dispatches per month is available for a maximum of 40 hours per month.

- Number of dispatches per year. A program that is dispatched for four hours and is available for 30 dispatches per year is available for a maximum of 120 hours per year.

- Energy strike price. This allows the user to enter an energy price at which the load will be paid for each dispatch hour. The value of the program is reduced by this out-of-pocket cost. The difference between the total avoided cost and this strike price is the value of curtailable load.[116]

Given these user inputs, the model calculates the optimal dispatch pattern and the avoided costs associated with that pattern. Model output includes program values in dollars per kW of dispatchable capacity and dollars per MWh of dispatched energy under perfect foresight. In reality, optimal dispatch will be impossible to achieve, as the utility will never know with 100% certainty whether the dispatch hours early in the year will turn out to be the highest-valued hours. However, this effect should be small, because much of the value of dispatchable programs stems from deferred or avoided T&D investments. The most valuable dispatch hours for T&D are associated with system peak load events, which are relatively easy to predict, especially to the extent that they are weather-related. These events will also generally coincide with periods of high energy prices.

4.3 Sensitivity Results with Baseline Price Forecast

The following charts and tables present dispatchable program values calculated using E3's baseline avoided cost forecast. These results demonstrate the sensitivity of dispatchable program value to program design parameters such as number of hours per dispatch and maximum number of dispatches per year. The results were calculated for secondary voltage customers in PG&E's Climate Zone 12. They include avoided T&D costs for a weighted average of all Planning Divisions within the Climate Zone.

Dispatchable program value can be displayed in two ways: in dollars per MWh, and in dollars per kW-yr. The per-kW value is simply the sum of avoided costs for a year given the program input parameters, divided by 1000 (avoided costs are defined for 1 MW). The per-MWh value is the per-kW value averaged over the number of dispatch hours. The first value gives an indication of the cost of using dispatchable programs to provide

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[116] *Woo, C. K., B. Horii and I. Horowitz (2002) "The Hopkinson Tariff Alternative to TOU Rates in the Israel Electric Corporation,"* Managerial and Decision Economics*, 23:9-19.*

capacity benefits. The second value is the average energy value for all the hours in which the capacity is dispatched.

As is shown in the following charts and tables, the per-kW value increases with the total number of available hours. Figure 85 shows the price duration curve and cumulative avoided cost curve for a program that is dispatched for four hours no more than 50 times per year. The hourly value of the highest four-hour period of the year is $1,574/MWh, occurring in August. There are five days with four-hour periods in which the per-MWh value exceeds $900, and ten days in which the four-hour per-MWh value exceeds $500. The average per-MWh value for this program is $375. The shaded area shows the total per-kW value increasing with the number of dispatch hours. The increase is steep for the first few hours where the per-MWh value is high, but levels off as the per-MWh declines. The total per-kW value for this program is $75.

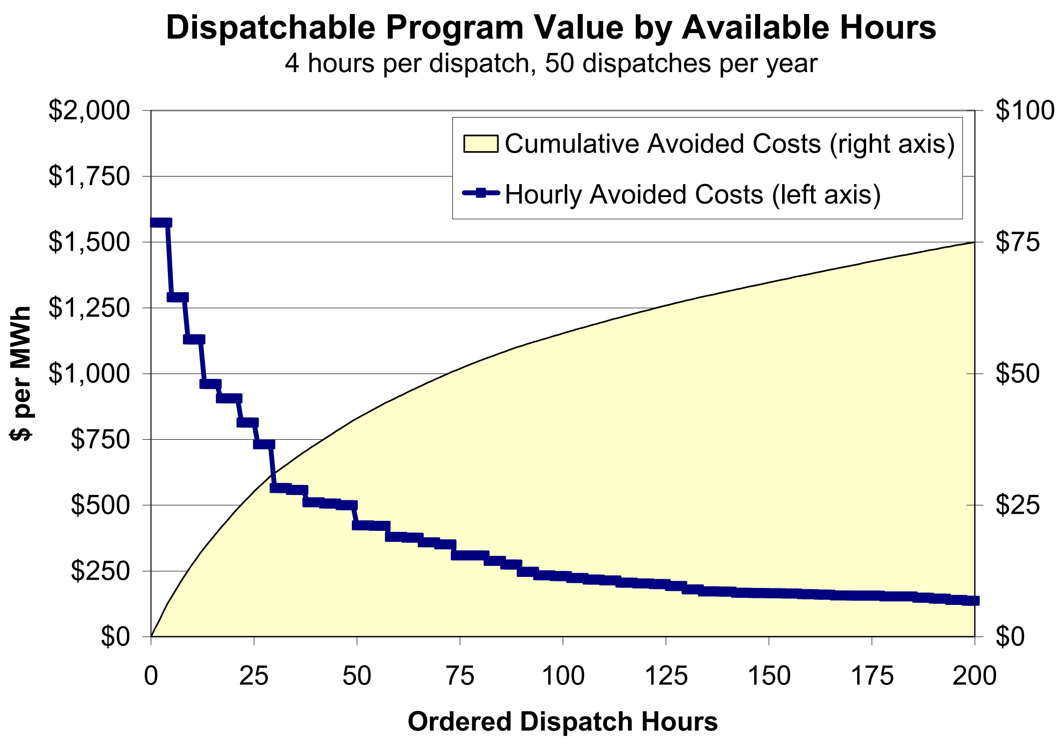

Figure 85: Dispatchable program avoided costs based on 4 hours per dispatch and 50 dispatches per year.
Calculated for secondary voltage customers in PG&E's Climate Zone 12, weighted average of all Planning Divisions.

Figure 86 shows the same chart for another program that is available for 200 hours per year, but with a different pattern of availability. This program is dispatched for only two hours per day, but is available for 100 dispatches per year instead of 50. The highest-priced hours have a similar avoided cost for this program, but the price duration curve drops off much more quickly. This indicates that increasing the number of days in which the program is available does not make up for the value that is lost by reducing the number of dispatch hours from four to two on the highest-priced days. The average hourly value of this program is $271 per MWh, and the total per-kW value is $54.22.

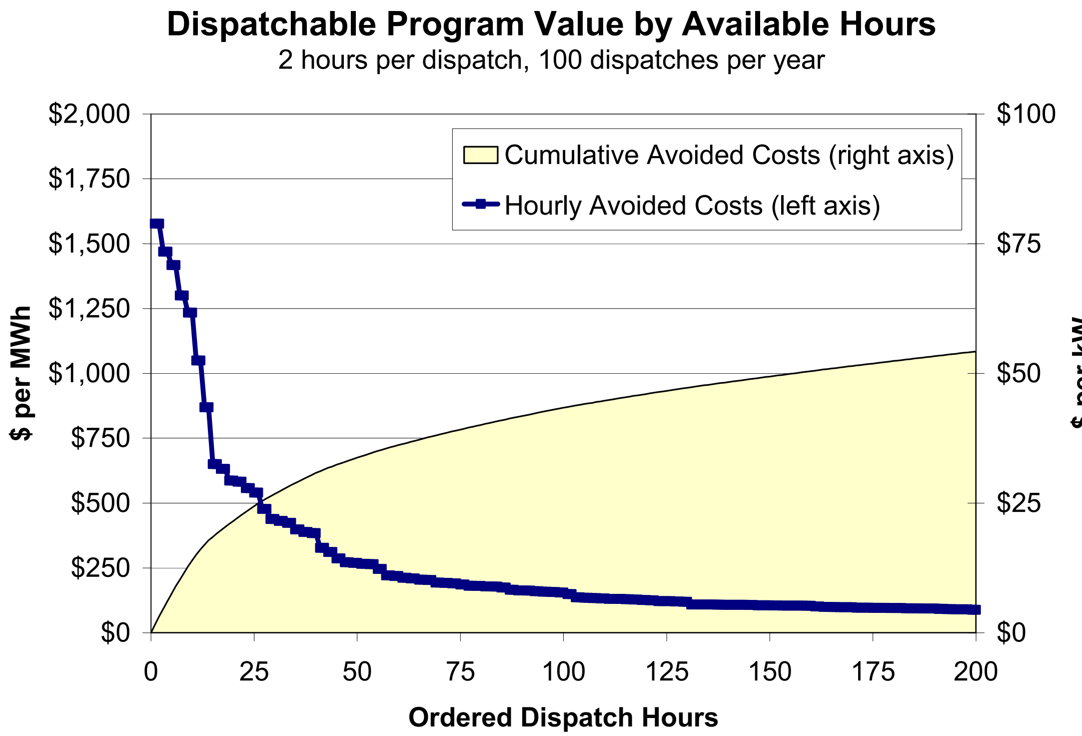

Figure 86: Dispatchable program avoided costs based on 2 hours per dispatch, 100 dispatches per year.
Calculated for secondary voltage customers in PG&E's Climate Zone 12, weighted average of all Planning Divisions.

Figure 87 shows how dispatchable program avoided costs vary with the number of available dispatch hours. The left-hand chart varies the number of dispatch hours per day, assuming 50 dispatches per year. Thus, a program that is dispatched for two hours per day has a total of 100 dispatch hours per year, while a program that is dispatched for eight hours per day has 400 dispatch hours available each year. The right-hand chart varies the number of dispatches per year, assuming four hours per dispatch. Thus, a program with 25 dispatches per year has a total of 100 dispatch hours available, while a program with 100 dispatches has 400 hours available.

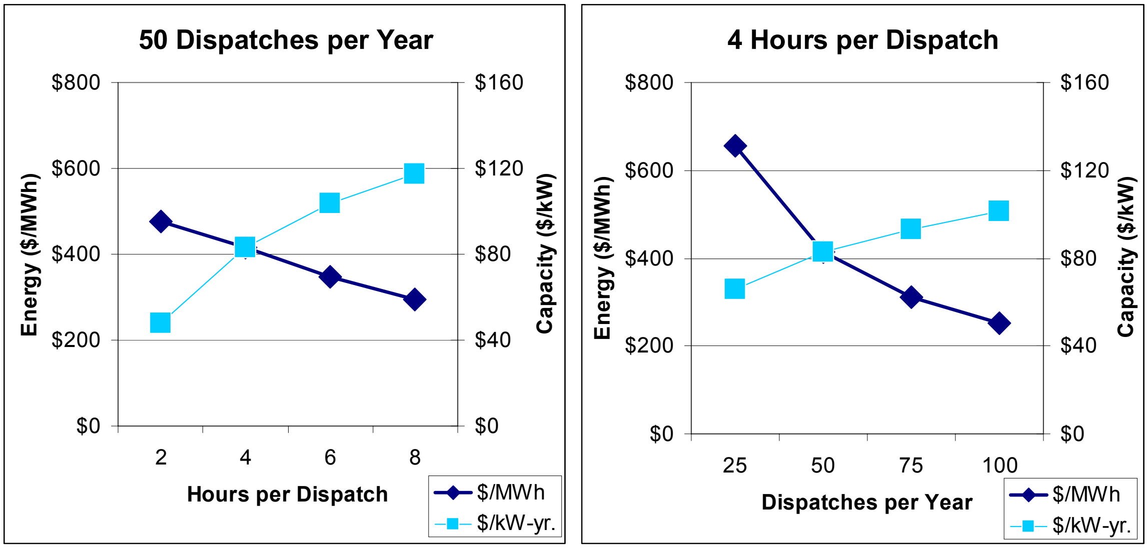

Figure 87: Dispatchable program avoided costs by hours per dispatch and dispatches per year.
Calculated for secondary voltage customers in PG&E's Climate Zone 12, weighted average of all Planning Divisions.

Both charts indicate that the per-kW value increases with the total number of dispatch hours, while the average per-MWh value declines. However, the convex shape of the per-kW value curve indicates diminishing marginal returns as the number of dispatch hours increases. The charts also show that increasing the number of hours per dispatch results in higher program values than increasing the number of dispatches per year, given the same total hours of availability.

Table 40 presents a range of dispatchable program avoided costs with different combinations of hours per dispatch and dispatches per year. Program avoided costs generally increase with hours per dispatch and total hours per year.

Table 40: Dispatchable program avoided costs as a function of hours per dispatch and dispatches per year. Assumes no constraint on dispatches per month.

Dispatches per Year	Hours per Dispatch	Hours per Year	per-kW Value
40	8	320	$109.19
80	4	320	$102.66
20	16	320	$92.75
40	5	200	$89.92
50	4	200	$86.42
20	10	200	$83.12
20	8	160	$78.85
40	4	160	$77.71
160	2	320	$74.78
20	6	120	$72.33
20	5	100	$67.08
40	3	120	$64.37
100	2	200	$63.06
10	16	160	$60.65
20	4	80	$59.63
10	12	120	$57.63
10	10	100	$55.94
80	2	160	$54.10
10	8	80	$53.86
320	1	320	$51.73
50	4	200	$49.82
40	2	80	$45.88
10	4	40	$41.32
160	1	160	$39.57
20	2	40	$34.94
100	1	100	$33.60
80	1	80	$31.19
40	1	40	$24.78
10	2	20	$24.35
20	1	20	$18.91

4.4 Developing Alternative Price Scenarios

The dispatch value shown in the previous section reflects the base case avoided cost forecast. Actual energy prices could turn out to be higher or lower than E3's forecast, just as actual load could turn out to be higher or lower than a utility's projection. Since E3 does not know the degree of uncertainty each utility faces, it provides these alternative price scenarios as a means to allow the avoided cost forecast to capture a dispatchable program's additional value in managing cost risk.

E3's approach is to develop a range of high, medium and low price scenarios based on historical electricity prices and allow the user to specify the probability that such scenarios occur. These three scenarios are supplemented with additional scenarios based on 1) E3's baseline forecast of the avoided cost of energy, and 2) user-specified natural gas prices and WECC hydroelectric output. Each scenario consists of an annual average electricity price, which replaces E3's forecast value during the years prior to resource balance. The annual price duration curve is then calculated based on the new value, and the dispatch model determines the optimal dispatch hours and program avoided cost given the alternative annual price. Finally, the avoided cost values of the individual scenarios are weighted by the user-specified probability, and the result is a single program avoided cost.[117]

Scenarios are developed by conducting statistical analysis of monthly average California PX electricity prices using Southern California natural gas prices and WECC hydroelectric output as explanatory variables. In order to isolate the effects of the electricity crisis, which are not expected to recur during the forecast period, a binary dummy variable is included that takes on a value of one from June 2000 through June 2001 and zero during all other months. The regression explains 93% of the variability in monthly average PX prices. Table 41 shows regression results, and Figure 88 demonstrates the close fit of predicted to actual values.

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[117] For computational ease, given the limitations of a spreadsheet-based model, a simplification is used: a weighted average annual average electricity price is calculated given user-specified probabilities for each of the alternative price scenarios before the price duration curve and optimal dispatch are applied. The two methods will yield identical values as long as the dispatch is the same.

Table 41: Results of Monthly Price Regression

Coefficient	Value	Std. Error	T-Value
Intercept	24.7917	25.4486	0.9740
Electricity Crisis	42.4062	11.7015	3.6240
SoCal Gas Price	15.0117	1.1215	12.3590
WECC Hydro Output	-0.0018	0.0014	-1.1316
R-square	*0.9384*		
Adj R-square	*0.9321*		

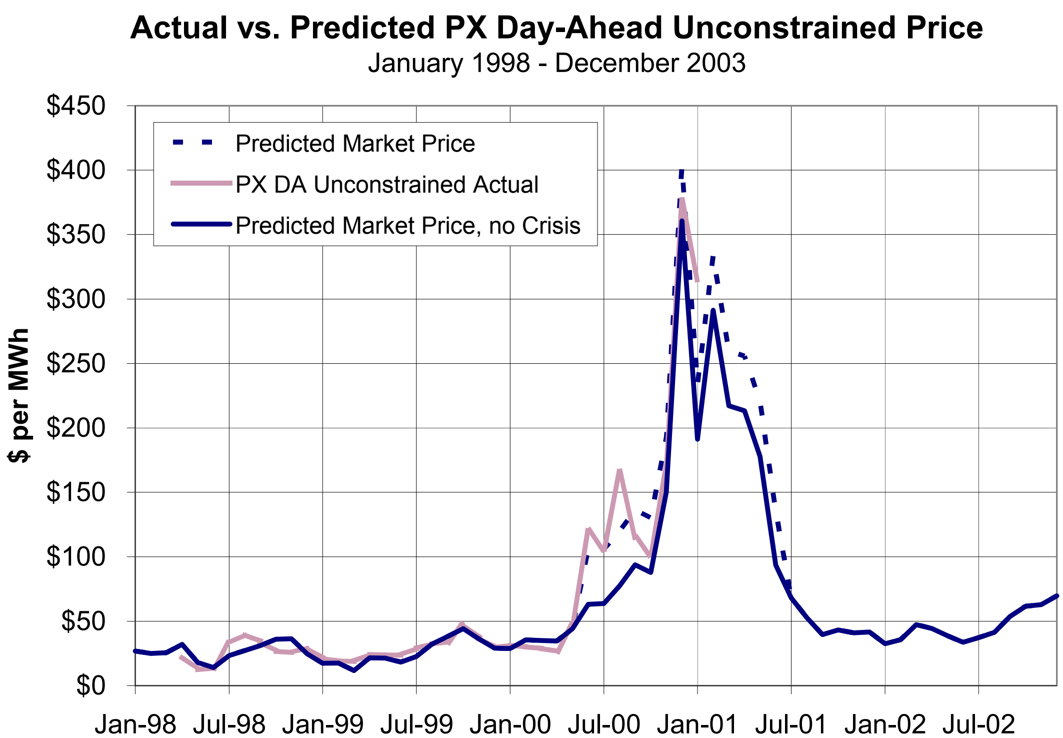

Figure 88: Actual versus Predicted PX Day-Ahead Unconstrained Price Jan. 1998-Dec. 2003

The regression analysis estimates monthly PX prices for April 1998 through January 2001, spanning the lifetime of the PX. However, the regression coefficients allow prices to be estimated for additional months during which there are no PX prices. This yields five full years of estimated prices, as indicated in Table 42 below.

Table 42: Alternative Electricity Price Scenarios

Year	Scenario	Gas Price ($/MMBtu)	WECC Hydro Output (GWh)	Predicted Price ($/MWh)
1998	L	$2.24	207,539	$26.64
1999	LL	$2.30	218,763	$25.84
2000	H	$6.20	184,266	$89.53
2001	HH	$7.84	130,042	$122.52
2002	M	$3.14	165,505	$46.52

The predicted prices for the five historical years can be sorted into five scenarios: LL, L, M, H and HH, as shown in the table. These data span a wide range of conditions, from very high hydroelectric output and electricity surpluses in 1998 and 1999 to historically low hydroelectric output combined with record gas prices in 2001.

Because it is possible that this range is wider than a more typical five-year period, E3's approach is to allow the user to assign probabilities to each of the scenarios, rather than to estimate probabilities given the statistical properties of the underlying data. The avoided cost is then based on the resulting weighted average price. Since the weighted average can take on any value inside this range, only the LL, M and HH scenarios are built into the spreadsheet model.

In addition to the three scenarios described above, the model allows the user to specify a custom scenario based on user-specified natural gas prices and hydroelectric output. These values are translated into electricity prices using the statistical relationships listed in Table 41. For example, if the user were concerned about a scenario that included relatively low hydro output (e.g., 150,000 GWh) and very high gas prices ($10/MMBtu), the resulting annual average electricity price would be $20.79 + 10.00 x 15.01– 0.0018 x 150,000/12 = $151.90. Finally, the model includes E3's baseline forecast as a fifth scenario. The probability associated with this scenario is defined as one minus the probabilities of all of the other scenarios.

Alternative price scenarios occur only for the period when California utilities make market purchases, i.e., prior to resource balance. When the resource balance year has been reached, the average annual energy price is based on the long-run marginal cost of new resources and is no longer subject to uncertainty. Thus, avoided costs for years after resource balance are simply E3's baseline forecasts.

4.5 Results with Alternative Price Scenarios

This section shows how avoided cost results can be sensitive to the alternative price scenarios employed and the probabilities assigned to them. Figure 89 shows price duration curves for the high and low alternative price scenarios assuming four hours per dispatch and 50 dispatches per year. The high scenario has avoided costs of $123/kW-yr., while the low scenario has avoided costs of $64/kW-yr. Recall that this program design had avoided costs of $75/kW-yr. in the base case.

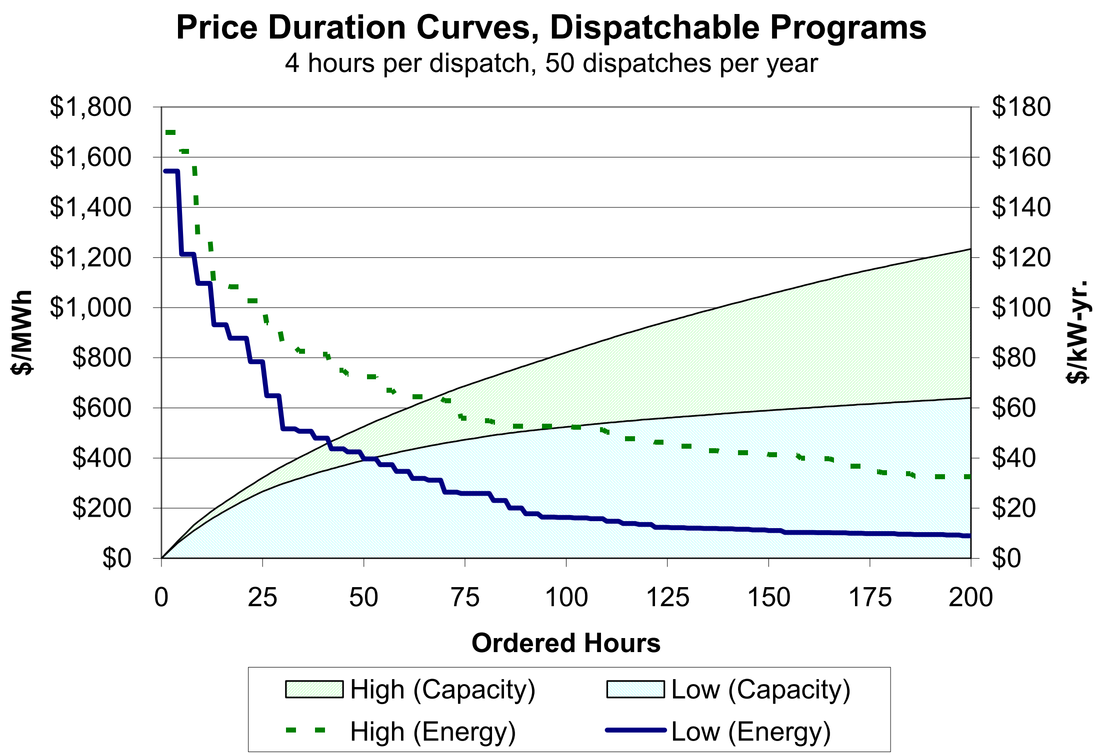

Figure 89: Price duration curves for dispatchable programs under alternative price scenarios.
Calculated for secondary voltage customers in PG&E's Climate Zone 12, weighted average of all Planning Divisions, under 4 hours per dispatch, 50 dispatches per year.

As the chart indicates, the difference in the scenarios is more pronounced during hours 25-175 than in hours 0-25 or 175-200. This is due to different dispatch patterns. The highest-cost hours of the year are driven by marginal T&D costs, and are similar in both scenarios. However, T&D costs drop off rapidly, and a different set of hours is selected for dispatch in the high price scenario, based on the higher energy value.

Of course, neither the high nor the low scenario can be expected with 100% probability. The scenarios must be assigned weights based on realistic expectations in order for the weighted average results to be meaningful. Suppose the user expected the high scenario to occur with 5% probability. Assigning 5% probability to the high scenario results in an expected energy price approximately $4 higher than the baseline scenario. This increases the value of a 4-hour, 50-dispatch per year program from $74.99 to $77.39, an increase of approximately 3.2%. Similarly, assigning probabilities of 10% to each of the low and high scenarios results in a 12% increase in the expected energy price and a 5% increase in the dispatchable program avoided costs. Table 43 shows avoided cost values for a range of alternative price scenarios which are calculated for secondary voltage customers in PG&E's Climate Zone 12, weighted average of all Planning Divisions, fewer than 4 hours per dispatch, 50 dispatches per year.

Table 43: Dispatchable program avoided costs for selected alternative scenarios.

Probability of: Baseline Scenario	Low Scenario	High Scenario	Weighted 2004 Energy Price	per-kW Value
100%	0%	0%	$45.76	$74.99
95%	0%	5%	$49.60	$77.39
90%	5%	5%	$48.60	$76.83
80%	10%	10%	$51.44	$78.67
50%	25%	25%	$59.97	$84.20

5.0 Effect of Reserve Margin Requirement on E3's Avoided Cost Estimates

On November 18, 2003, ALJ Walwyn issued a proposed decision and Commissioner Peevey issued an alternate decision in Rulemaking 01-10-024, *Order Instituting Rulemaking to Establish Policies and Cost Recovery Mechanisms for Generation Procurement and Renewable Resource Development*. Both decisions, if adopted, would obligate California investor-owned electricity utilities to acquire sufficient reserves, including a Planning Reserve Margin (PRM) of at least 15% of customer load located within their service territory.

E3's current long-run avoided cost forecast has not explicitly considered a 15% PRM requirement. It is therefore reasonable to question if the PRM requirement demands modification to E3's avoided cost methodology and results. E3's answer to this question is "no" because E3's avoided cost computation, as demonstrated below, fully accounts for ancillary services (AS) procurement and generation planned and unplanned outages. **The capacity associated with the AS cost and LRMC cost adjustment for outages provides a reserve margin of 18%**. Hence, it is unnecessary to adjust E3's baseline forecast at this time. However, E3 recommends that this issue be revisited when the Commission issues a final decision in this rulemaking.

E3's derivation of the 18% reserve margin is based on ALJ Walwyn's decision (CPUC, 2003, pp. 20-21):

In order to ensure reliability, a grid operator must ensure that there are sufficient resources available to meet peak demand, plus an additional reserve to accommodate unexpected outages. The level of the reserve is determined by the Western Electricity Coordinating Council and is approximately 7% of peak demand. This is the operating reserve.

"Planning reserves" involve a longer-term perspective of ensuring that in real-time there will be sufficient energy to meet peak demand plus needed operating reserves. Typically this requires that a utility have more than 7% reserves, since at any given time some percentage of plants may not be available due to such factors as maintenance, forced outage, fuel limitations, or in the case of hydroelectric power (insufficient water conditions).

The Joint Recommendation proposes definitions for "operating reserve margin" and "planning reserve margin" that are reasonable. The Joint Recommendation defines:

> Planning Reserve Margin ("PRM"): The reserve margin shall be an obligation over and above the capacity required to meet peak demand. PRM is computed as follows: PRM = ((Dependable Capacity/Peak Load) – 1) x 100%. In calculating PRM, "Dependable Capacity" shall not be reduced to reflect Reasonably Expected Resource Outages.
>
> Operating Reserve Margin ("ORM"): ORM shall be used for purposes of reviewing resource adequacy over a shorter term, such as a year or less and shall be applicable to short-term procurement plans. ORM is computed as follows: ORM = (((Dependable Capacity – Reasonably Expected Resource Outages)/Peak Load) – 1) x 100%.

While ALJ Walwyn's draft decision does not define "Dependable Capacity", it clearly states that the 15% PRM requirement encompasses operating reserves and the capacity required to handle expected generating unit outages. The question herein is "does E3's avoided cost computation account for operating reserves and expected generating unit outages?" If the answer is "yes", it is unnecessary to adjust E3's avoided cost forecast to reflect the effect of the Commission's adoption of the PRM requirement.

E3's affirmative answer to the above question recognizes that the reliability adder in E3's forecast captures the AS cost of procuring operating reserves, regulation capacity and replacement reserves. This adder is about 2.84% of the energy price using 1999-2003 data (excluding the crisis period) from the CASIO website. The same data indicate the capacity numbers underlying the 2.84% estimate range from 3-6% of load for regulation, 6-8% for operating reserves, and 0-2% replacement reserves. Thus, AS procurement alone yields 9-12% reserve margin.

For the load-resource balance year and beyond, E3's generation avoided cost forecast is the LRMC that assumes a capacity availability factor of 91.6% for a new CCGT power plant. Hence, the unit is assumed to be unavailable 8.4% of the time, due to a forced outage rate of 4.6% and a planned maintenance outage rate of 3.8%.[118] This imperfect availability factor adds to the cost of owning and operating the CCGT. As

“Reasonably Expected Resource Outages” includes both planned and unplanned outages, E3’s LRMC computation captures a 9.2% (= (1/.916) – 1) reserve margin.

Recall that the reliability adder based AS procurement implies a 9-12% reserve margin, whereas the LRMC computation implies a 9.2 % reserve margin. Taken together, E3’s avoided cost computation for the load-resource balance year and beyond has an inherent reserve margin of 18%. Hence, the adoption of a 15% PRM requirement should not alter E3’s avoided cost methodology and results.

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[118] CEC, Comparative Cost Of California Central Station Electricity Generation Technologies, June 5, 2003

6.0 Appendices

6.1 Appendix A: Energy Division Policy Manual – Referenced Excerpts PP. 15-23

4. Cost-Effectiveness

Though not every program selected will necessarily be cost-effective given the variety of policy objectives being pursued, the Commission will select a cost-effective portfolio of programs.

Measuring the cost-effectiveness of energy efficiency programs serves several purposes:

- To assist in determining whether a program is warranted (prospectively or on a continuing basis);
- To assist in determining prospectively what program activities are appropriate;
- To assist in understanding motivations for program participation by customers and service providers to customers;
- To assist in determining funding allocations for various programs;
- To assist in modifying programs during operation to increase their effectiveness;
- To assist in assessing retroactively to what extent programs have been successful in achieving the Commission's policy objectives.

Methodology

Cost-effectiveness is an important measure of value and performance. In order to ensure a level playing field for multiple programs, the Commission will continue to use the standard cost-effectiveness methodologies articulated in the California Standard Practices Manual (SPM): Economic Analysis of Demand-Side Management Programs. See Appendix A of this manual for information on how to obtain a copy of the SPM.

Two cost-effectiveness tests identified in the SPM are particularly important to the Commission in evaluating energy efficiency programs on an ongoing basis. The first is the Total Resource Cost (TRC) test – Societal Version. This test, as defined in the SPM, is intended to measure the overall cost-effectiveness of energy efficiency programs from a societal perspective, taking into account benefits and costs from more than just an individual perspective. The Commission will primarily rely upon the results of this test in assessing program cost-effectiveness.

The TRC should be calculated by treating programs as multi-year (rather than single-year) activities so that programs explicitly designed as integrated, multi-year strategies, which may have modest benefits (and / or high start-up costs) in early program years, could be evaluated considering the expected larger benefits (and / or lower costs) in later program years.

The Commission will not rely on the TRC exclusively in making funding allocation decisions among programs, but instead will use cost-effectiveness as one criterion among many (as summarized in Chapter 1 above).

In addition to the TRC test, the Commission will rely on the Participant Test (also identified in the SPM) to evaluate programs that are aimed at inducing individual customers to make energy efficiency decisions. The Participant Test measures the cost-effectiveness of a program from the perspective of energy consumers participating in the program. Proposals for programs designed to provide financial incentives directly to customers should include the results of the Participant Test as well as the TRC.

In addition to the SPM, parties proposing programs should refer to the workbook template provided by the Energy Division.

Established Cost-Effectiveness Inputs

Certain inputs to the cost-effectiveness tests identified in the SPM have already been established by the Commission. Parties should use these inputs presenting their cost-effectiveness analysis to the Commission in their program proposals. These established inputs, along with their sources, are given below. All of the values given below represent the best-available data at the time of adoption of this manual. The Commission will update these assumptions periodically.

Effective Useful Lives of Energy Efficiency Measures
Standard values for effective useful lives (EULs) or measures are the standard assumptions used to determine the life-cycle savings associated with certain common energy efficiency measures. The EUL is generally an estimate of the median number of years that the measures installed under a given program are still in place and operable.[8] If a program proposal involves any of the measures listed below, the standard assumption should be used. If a proposed program involves a measure not listed below, the applicant should propose an appropriate assumption for the EUL, citing any relevant studies or other data sources. In order to minimize uncertainty, EULs will be limited to a maximum of 20 years, even if particular devices may be expected to survive longer.

[8] Source: *Procedures for the Verification of Costs, Benefits, and Shareholder Earnings from Demand Side Management (DSM) Programs (MA&E Protocols).* See also p. 26 of September 25, 2000 CALMAC report prepared pursuant to Ordering Paragraph 9 of D.00-07-017.

Table 4.1. Effective Useful Lives of Energy Efficiency Measures

Measure	Lifetime	Measure	Lifetime
Lighting		**HVAC**	
Ballast – Dimmable	16	Air Conditioners – High Efficiency	15
Ballast – Electronic	16	Boiler – High Efficiency	20
CF- Screw-in Replaceable Lamp (Modular)	8	Bypass/Delay Timer	15
Compact Fluorescent Hardware Fixture	16	Chiller – High Efficiency	20
Delamping/Fixture Modifications/Removal	16	Chiller – Variable Speed Drive	20
Exit Sign – CF Hardware Kid/LED/ Electro-Luminescent	16	Cooling Towers/Evaporative Condenser	15
Fluorescent Fixture – T8	16	Furnace – High Efficiency	20
Halogen Lamp	0.6	Glazing – High Shade Coefficient	20
HID Fixture	16	Heat Pump – Packaged	20
Occupancy Sensor	8	HVAC/Space Heating/ Efficiency (Gas)	15
Photocell	8	Insulation	20
T8 Fixtures – 17 Watt Lamp, 2ft or 32-watt Lamp, 4ft	16	Reflective Window Film/ Windows	10
Time Clock – Lighting	8	Set-Back Thermostat	11
Fixture: T8 Lamp & Electronic Ballast	16	Time clock	10
High Efficiency Lighting	16	Heat Pump – Split System	20
High Output T5 Fixture	16	AC Packaged Terminal Units	15
Induction Lamps	2	Adjustable Speed Drive	15
Induction Fixture	16	Ground Source Heat Pump	15
Indoor or Outdoor System Modification	16	Heat Pump with Integrated Water Heating	20
Lighting Controls	16	Packaged HVAC Systems	15
Daylighting Controls	16	Water Cooled Chillers	20
Lighting Power Density	16	Insulation Package	20
Refrigeration		Energy Management System	15
Auto Closer for Cooler/Freezer	8	Reduce Internal Load	15
Door Gaskets	4	Evaporative Coolers	15
Floating Head Pressure	16	HVAC/Refrigeration – SPC	20
Heatless Door	16	Nonresidential Gas – AC	20
Humidistat Control for Anti-Sweat Heater	12	**Hot Water**	
Insulation on Refrigeration Suction Line	11	Water Heater – Gas	15
Night Covers for Display Cases	5	Horizontal Clothes Washer	10

Table 4.1 (continued). Effective Useful Lives of Energy Efficiency Measures

Measure	Lifetime	Measure	Lifetime
PSC Evaporator Motor – Walk-in / Display	16	Efficient Dishwashing	5
Refrigeration Case Doors – Glass / Acrylic	12	Water Heater Controls	15
Refrigerator Case with Doors	16	Domestic Hot Water Boiler	20
Refrigerator Condensate Evaporator – Elec / Non Elec	8	**Miscellaneous**	
Strip Curtains for Walk-Ins	4	Cooking Equipment	12
Ballast: Electronic, for display case	16	High Efficiency Engine	15
Defrost	16	Kiln / Oven / Furnace	20
FHP & EFF Conditioner	16	Thermal Night Curtains	5
High-efficiency Liquid Suction Heat Exchangers	16	Custom Measures – SPC	15
Night Shields on Refrigerator and Freezer Cases	16	Local Government Initiatives	11
Refrigerator: Evaporative Fan Controller	5	Extrusion Equipment	15
Supermarket Systems	14	Audits	3
		Plug Load Sensor	10
		Information	1
		High Efficiency Motors	15
		Variable Frequency Drives	15
		Process Overhaul	20
		Pump Test	15
		System Controls	15

Net-to-Gross Ratios

Net-to-gross ratios (NTGRs) are used to estimate free-ridership occurring in energy efficiency programs. Free riders are program participants who would have undertaken an activity, whether or not there was an energy efficiency program promoting that activity. An NTGR is a factor that represents the net program load impact divided by the gross program load impact. This factor is applied to gross program savings to determine the program's net impact.[9] This factor is important in determining actual energy savings attributable to a particular program, as distinct from energy efficiency occurring naturally (in the absence of a program).

Applicants should refer to the SPM to determine the appropriate manner in which to use NTGRs in submitting program cost-effectiveness information.

Program proposals should use the applicable NTGRs listed below. If a program is not listed below, or if a proposed program design deviates substantially from past design of related programs, program proposals may utilize a default NTGR of 0.8 until such time

[9] Source: p. 26 of September 25, 2000 CALMAC report, referencing D.00-07-017 ordering paragraph 9.

as a new, more appropriate, value is determined in the course of program evaluation. All existing programs not listed below shall also use a default value of 0.8.

Table 4.2. Net-to-Gross Ratios

Program Area/Program	Net-to-Gross Ratio
Residential	
Appliance early retirement and replacement	0.80
California Home Energy Efficiency Rating System (CHEERS)	0.72
Residential Audits	0.72
Refrigerator Recycling / Freezer Recycling	0.53 / 0.57[10]
Residential Contractor Program	0.89
Emerging Technologies	0.83
All other residential programs	0.80
Nonresidential	
Advanced water heating systems	1.00
Agricultural and Dairy Incentives	0.75
Coin Laundry and Dry Cleaner Education	0.70
Commercial and agricultural information, tools, or design assistance services	0.83
Comprehensive Space Conditioning	1.00
Lodging Education	0.70
Express Efficiency (rebates)	0.96
Energy Management Services, including audits (for small and medium customers)	0.83
Food Services Equipment Retrofit	1.00
Industrial Information and Services	0.74
Large Standard Performance Contract	0.70[11]
All other nonresidential programs	0.80
New Construction	
Industrial and Agricultural Process	0.94
Industrial new construction incentives	0.62
Savings by Design	0.82[12]
All other new construction programs	0.80

Discount Rate

In evaluating all energy efficiency program proposals, the Commission shall use a pre-established discount rate of 8.15%. This standard assumption, used as the default in

[10] D.03-04-055, Attachment 2, page 7 (Program Descriptions)

[11] "Improving the Standard Performance Contracting Program: An Examination of the Historical Evidence and Directions for the Future," XENERGY, Nov. 29, 2001, page E-6, footnote 2.

[12] "An Evaluation of the Savings By Design Program," RLW Analytics, March 31, 2003, page 3, Table 2 and page 5.

recent years, may be updated in the future. The discount rate is used simply to translate potential benefits in future years into current year terms.

Avoided Costs

In order to estimate the value of the energy efficiency occurring as a result of program activities, parties will need to be able to estimate the "avoided cost" of the provision of that supply of energy. Avoided costs represent the value of the electricity or natural gas that, in the absence of a program, would need to be procured and delivered to an individual consumer. When an energy efficiency programs creates a reduction in demand for electricity or natural gas, costs are avoided from the perspective of the consumer, the utility, and society.

The Commission will continue to use six sets of avoided cost streams for the generation of electricity and the procurement of natural gas. These values should be used in the TRC-Societal Version Test, to apply to all program proposals on a statewide basis:

<u>Electric</u>
- Avoided generation costs
- Avoided transmission and distribution costs
- Environmental externalities

<u>Gas</u>
- Commodity procurement costs
- Transmission and distribution costs
- Environmental externalities

The Commission will use retail rates for the avoided cost streams used in the Participant Test, as prescribed by the SPM. These retail rates are specific to both the IOU territory and the program participant rate class in which an energy efficiency program is operating.

Not all of the above-avoided cost streams are necessary for all cost-effectiveness tests described in the Standard Practices Manual. Refer to that manual for more details on how to use the avoided cost streams.

Table 4.3 gives the Commission's generation of electricity and procurement of natural gas avoided cost assumptions. Sources of each stream of values are given below the table. These estimates will be updated as necessary. Any new avoided costs will be utilized on a prospective basis for future program planning, and not applied retroactively to evaluate existing programs that were developed based on an earlier set of avoided cost assumptions.

Table 4.3. Electric and Gas Avoided Costs

	Electric ($ per MWh)				Gas ($ per therm)			
Year	**Generation**	**Trans. & Dist.**	**Env. Ext.**	**Total Electric**	**Commodity**	**Trans. & Dist.**	**Env. Ext.**	**Total Gas**
2002	$99.05	$5.25	$6.55	$110.85	$0.49	$0.03	$0.06	$0.58
2003	$56.71	$5.50	$6.80	$69.01	$0.37	$0.03	$0.06	$0.47
2004	$53.41	$5.74	$7.04	$66.19	$0.34	$0.03	$0.06	$0.43
2005	$54.51	$6.00	$7.20	$67.71	$0.35	$0.03	$0.06	$0.45
2006	$49.61	$6.20	$7.40	$63.21	$0.37	$0.03	$0.07	$0.47
2007	$51.55	$6.50	$7.60	$65.65	$0.39	$0.03	$0.07	$0.49
2008	$53.25	$6.75	$7.85	$67.85	$0.40	$0.04	$0.07	$0.51
2009	$55.10	$7.04	$8.14	$70.28	$0.42	$0.04	$0.07	$0.53
2010	$57.08	$7.34	$8.34	$72.76	$0.44	$0.04	$0.07	$0.55
2011	$58.96	$7.60	$8.60	$75.16	$0.38	$0.04	$0.08	$0.49
2012	$61.38	$7.94	$8.84	$78.16	$0.40	$0.04	$0.08	$0.51
2013	$63.99	$8.30	$9.10	$81.39	$0.42	$0.04	$0.08	$0.53
2014	$66.76	$8.60	$9.40	$84.76	$0.43	$0.04	$0.08	$0.56
2015	$69.76	$9.00	$9.70	$88.46	$0.45	$0.04	$0.09	$0.58
2016	$73.00	$9.34	$9.94	$92.28	$0.48	$0.04	$0.09	$0.61
2017	$76.49	$9.74	$10.24	$96.47	$0.50	$0.04	$0.09	$0.63
2018	$80.23	$10.14	$10.54	$100.91	$0.52	$0.05	$0.09	$0.66
2019	$84.28	$10.55	$10.81	$105.64	$0.54	$0.05	$0.10	$0.68
2020	$88.44	$10.59	$11.08	$110.11	$0.57	$0.05	$0.10	$0.71
2021	$92.87	$11.12	$11.36	$115.34	$0.59	$0.05	$0.10	$0.74
2022	$99.42	$11.52	$11.67	$122.61	$0.61	$0.05	$0.10	$0.76
2023	$102.22	$11.91	$11.98	$126.11	$0.64	$0.06	$0.11	$0.81

Data Sources

Electric

1. **Avoided Costs of Generation.** These values are based on an August 2000 California Energy Commission forecast of market clearing prices using the MULTISYM model. Values for certain years were updated based on direction given in an October 25, 2000 ALJ Ruling on PY2001 planning in A.99-09-049, subsequently adopted by the Commission in D.01-01-060. Modifications to the CEC forecast were as follows:

Table 4.4. Assumptions for Electric Generation Costs

Program Years	**Basis**
2004-2010	CEC market clearing price forecast, plus 20%
2011-2020	CEC market clearing price forecast
2021-2023	CEC market clearing price escalated by growth rate over previous five years

In addition, the values reflected in Table 4.3 incorporate an “on-peak” multiplier, as ordered in the ALJ ruling of October 25, 2000 to account for the system value of reduced load on reducing market clearing prices, pursuant to AB970, Section 7,

Table B, Paragraph 8, and the September 14, 2000 and October 25, 2000 ALJ rulings in A.99-09-049. The on-peak multipliers are described in Table 4.5.

Table 4.5. On-Peak Multipliers

Program Years	Multiplier
2004-2005	2.0X
2006-2021	1.5X

2. **Electric Transmission and Distribution Avoided Costs.** The T&D avoided cost value-stream is calculated based upon a statewide average of weighted forecasts of avoided T&D costs across utility service territories. This forecast was based upon 1996 sales for each utility, and converted from $/kW to $/MWh by assuming a 0.6 load factor. These values were adopted by the Commission in Resolution E-3592.

3. **Electric Environmental Externalities.** These values were adopted by the Commission in Resolution E-3592.

4. **Gas Avoided Commodity Costs.** Gas procurement costs are based on the CEC's August 2000 base case price forecast for electric generation.

5. **Gas Transmission and Distribution Avoided Costs.** These values represent a weighted average of gas T&D costs in PG&E, SDG&E, and SoCalGas territories, as represented by each utility in their PY2000 annual reports.

6. **Gas Environmental Externalities.** These values were recommended by the CBEE and adopted by the Commission in Resolution E-3592.

All values (2-6) have been escalated by their average growth rate over the previous five years for the years 2022-2023.

Table 4.6 gives the Commission's avoided cost assumptions used in the Participant Test. These avoided costs are based on current IOU retail electricity and natural gas rates, and will be escalated in Participant Test calculations based on the CEC's GDP deflator series.

Table 4.6 Avoided Cost Assumptions by Service Territory

	Electricity ($/kWh)			Natural Gas ($/therm)		
	PG&E	SCE	SDG&E	SoCalGas	PG&E	SDG&E
Residential	0.13	0.14	0.16	1.07	0.89	1.31
Agricultural	0.14	0.11	0.15	0.74	N/A	N/A
Small Commercial	0.17	0.18	0.17	0.87	0.87	0.93
Medium Commercial	0.16	0.15	0.12	0.77	0.73	0.81
Large Commercial	0.14	0.13	0.12	0.63*	0.67*	0.63*

* Large commercial gas rates are based on a $0.50/therm commodity cost.

Flexible Cost-Effectiveness Inputs

The Commission uses CEC's Database for Energy Efficient Resources (DEER)[13] for two crucial sets of inputs to the standard cost-effectiveness tests. These are:

- Incremental Measure Costs
- Per-Unit Energy Savings Estimates

This database is updated periodically and available over the Internet, (at http://www.energy.ca.gov/forecasting/DEER.html), but may not offer appropriate values for all circumstances. If information for cost-effectiveness test inputs is not available through this database, parties proposing programs must develop and include the necessary information using alternate sources. If the source of incremental measure cost or per-unit energy savings assumptions is not the DEER, documentation supporting the inclusion of the new information must be provided.

[13] The California Public Utilities Commission provides funding for the CEC Database for Energy Efficient Resources.

6.2 Appendix B: Environmental Avoided Cost Calculation References

Specific Generation Plant Emission Data

Information from the documents listed below was used to establish emission rates for based on plant heat rate for natural gas-fired plants throughout California.

1. Blythe Energy Project: Commission Decision on the Application for Certification, Blythe Energy Project, Docket No. 99-AFC-8, California Energy Commission, March 2001
2. Calpine Gilroy Peaker: Final Major Facility Review Permit: Issued to Gilroy Energy Center, LLC, Facility #B4512, Bay Area Air Quality Management District, July 18, 2003
3. Contra Cost 8: Final Major Facility Review Permit, Issued to Southern Energy Delta, LLC, Contra Costa Power Plant Facility #A0018, Bay Area Air Quality Management District, October 19, 2000
4. Creed Energy Center: Final Major Facility Review Permit, Issued to: Creed Energy Center, LLC, Facility #B4414, March 6, 2003
5. Delta Energy Center: Final Determination of Compliance, Delta Energy Center, Bay Area Air Quality Management District, Application 19414, October 21, 1999
6. East Altamont Energy Center: Final Determination of Compliance, East Altamont Energy Center, LLC., Bay Area Air Quality Management District, Application 2589, July 10, 2002.
7. Los Esteros Critical Energy Facility Project, Application for Certification (01-AFC-12), Santa Clara County, Commission Decision, July 2002.
8. Los Medanos Energy Center: Proposed Major Facility Review Permit: Issued to Los Medanos Energy Center, Facility B1866
9. Magnolia Power Project, Commission Decision on Application for Certification (01-AFC-6), Los Angeles County, City of Burbank, March 2003
10. Moss Landing Power Project. Commission Decision and Order, October 25, 2000.
11. Metcalf Energy Center Commission Decision on the Application for Certification, Docket No. 99-AFC-3, Santa Clara County, California Energy Commission, September 2001
12. Palomar Energy Project, Commission Decision on Application for Certification, (01-AFC-24), San Diego County, August 2003
13. Pico Power Project, Application for Certification (02-AFC-3), Santa Clara County, Commission Decision, September 2003
14. Russell City Energy Center, Application for Certification (01-AFC-7), Alameda County, July 2002
15. Tesla Power Project, Application for Certification, Alameda County, October 2001
16. Tracy Peaker Project, Application for Certification (01-AFC-16), San Joaquin County, July 2002.

California Market: Emission Reduction Credit Offset Information

- "Emission Reduction Offsets Transaction Cost Summary Report for 2002", California Air Resources Board, California Environmental Protection Agency, March 2003

- "Emission Reduction Offsets Transaction Cost Summary Report for 2001", California Air Resources Board, California Environmental Protection Agency, April 2002

- "Emission Reduction Offsets Transaction Cost Summary Report for 2000", California Air Resources Board, California Environmental Protection Agency, March 2001

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6.3 Appendix C: Comparison of T&D Avoided Cost Calculation Methods

Present Worth Method (PW)

Present worth reflects the savings associated with such an investment deferral, but assumes that the existing plan changes only in timing. This assumption is reasonably valid for relatively small load changes, but the overall plan could change significantly if relatively large changes are encountered. PW loses some of its methodological advantages as data is aggregated across areas or system-wide values are used. For example, all of the utilities plan for electric transmission marginal costs on a system-wide basis. San Diego plans its electric distribution for the system as well. In addition, the utilities only differentiate gas T&D by customer class, not area or time.

The PW method estimates avoided cost as the opportunity cost of planned capital expenditures from a permanent decrease in load. This avoided cost is reflected in the savings associated with shifting the expansion plan cost stream into the future, often referred to as the deferral value. The PW method yields an avoided cost estimate that varies by planning year, reflecting the greater marginal costs when investment is imminent. An expression of the PW formula is:

$$MC[PW] = \frac{\sum \left[\frac{Invest}{(1+r)^{y}} - \frac{Invest * (1+i)^{\Delta y}}{(1+r)^{y+\Delta y}} \right]}{LoadChange} * AnnualizationFactor$$

where:

Invest = annual demand-related investments in capacity by area ($);
i = escalation rate for the investments;
r = discount rate; y = year;

LoadChange = estimated average change in peak load by area for the planning period;

Δy = deferral caused by load change (annual peak load growth divided by *LoadChange*); and

Annualization Factor = real economic carrying charge for the planning period, grossed up by a variable expense factor.

Total Investment Method (TIM)

The TIM computes an arithmetic average by dividing the undiscounted total investment during the planning horizon by the undiscounted total load growth during the same period. The resulting unit marginal cost is then annualized using a Real Economic Carrying Cost (RECC) factor.[119] The method is not responsive to the timing of investments or load growth, only their cumulative total during the planning period. The TIM method is expressed as

$$MC[TIM] = \frac{\sum Invest}{\sum LoadGrowth} * RECC$$

where *Invest* = sum of investments over the forecast period; *LoadGrowth* = the sum of the annual incremental demand-related load growth over the forecast period; and *RECC* = the real economic carrying charge.

[119] The RECC levelizes a stream of future payments to an annualized real cost. It measures the per dollar savings of deferring an investment one year, taking account of the stream of replacement investments. It includes a marginal expense factor to reflect variable operation and maintenance costs and other fees.

Discounted Total Investment Method (DTIM)

The DTIM is an extension of the TIM, except that DTIM discounts both the expenditures and the load growth. DTIM computes a marginal cost by dividing the present value of the planning period's investment by the present value of the load growth. The ratio is annualized using a RECC factor. The Discounted Total Investment Method (DTIM) is responsive to investment timing, but remains constant if the load and cost both move by the same increment in time and thereby does not reflect any cost savings associated with a deferred investment due to a decrease in demand. DTIM is expressed as

$$MC[DTIM] = \frac{\sum \frac{Invest}{(1+r)^y}}{\sum \frac{LoadGrowth}{(1+r)^y}} * RECC$$

where *Invest* = sum of investments over the forecast period and *LoadGrowth* = the sum of the annual incremental demand-related load growth over the forecast period; *r* = discount rate; and *y* = the year in the forecast period.

The rationale for discounting both the numerator and denominator is to normalize all investments and loads to a single time period. The intuitive reason for this is that the discounted load makes it so that DTIM accurately represents a constant price that if paid for the load as it occurs would exactly match the present value of the investment stream.

NERA Regression Method

National Economics Research Associates, Inc. (NERA) developed a linear regression technique used by SDG&E and SoCal Gas in calculating natural gas T&D marginal costs. The NERA regression methodology obtains a marginal unit capital cost by regressing the cumulative changes in investment with cumulative changes in load. In the case of SDG&E and SoCal Gas, the analysis utilizes a combination of 10 years of historical and 5 years of forecast period data. The marginal unit is annualized using the RECC factor and grossed up for marginal expenses. Although the regression method is accurate for calculating historical marginal costs, it assumes that the future will resemble the past and breaks the link between forecast investments and forecast load growth.

Replacement Cost New Method (RCN)

RCN reflects the estimated cost to reproduce the existing facilities at prevailing prices. SCE uses the method for its electric T&D marginal costs. The total RCN cost of the system is usually estimated by collecting historical asset value data (differentiated by location and component type), and then converting to current values. The RCN per unit of load served (can be measured as non-coincident peak, coincident peak, diversified peak, "equivalent demand", or others) estimates the average cost of meeting demand, the rationale being that it reflects the appropriate opportunity cost. This part of the calculation is based only on historical data. The average cost is then converted to a marginal cost by multiplying by an "engineering elasticity" or elasticity of capital cost with respect to demand. This elasticity is usually derived using a forward-looking load and project projection, deriving the percentage change in RCN with percentage change in load based on forecast values. A simplified formulation is

$$MC[RCN] = \frac{\sum Invest}{\sum (CapacityAdded) * AssetUtilizationFactor} * RECC$$

where *Invest* = the additions to RCN from new demand-related investments in the planning period; *CapacityAdded* = the incremental growth in capacity; *AssetUtilizationFactor* = the area's design demand divided by the area's transmission or distribution capacity; *RECC* = the real economic carrying charge.

RCN has been employed mainly for ratemaking, designed to reflect value of service and thereby does not reflect the actual costs that must be incurred in response to changes in demand. RCN also does not capture fact that slower growing areas offer higher potential for deferral savings.

Derivation of the simplified formulation is shown below.

$$MC = \frac{\left(RCN[Total]_{2001} * Esc_{2004} * GPLF * RECC + O\,\&\,M\right) * CWC * Elast}{DesignDmd}$$

$$Elast = \frac{\dfrac{RCN[New]}{RCN[Total]_{2001}}}{\dfrac{Cap[New]}{Cap[Total]_{2001}}}$$

$$MC = \frac{\left(\dfrac{RCN[New]}{Cap[New]} * Esc_{2004} * GPLF * RECC\right) * CWC}{\dfrac{DesignDmd}{Cap[Total]_{2001}}} + \frac{O\,\&\,M * CWC * Elast}{DesignDmd}$$

$$\frac{DesignDmd}{Cap[Total]_{2001}} \textit{ shows the asset utilization and is about } 89\% \textit{ for Rural, } 96\% \textit{ for Urban}$$

6.4 Appendix D: Market-based forecast of gas price in California

6.4.1 Introduction

Natural gas market reform and deregulation since the mid-1980s have created wholesale spot markets that disperse across North America (Lee, 2004). Empirical evidence supports the hypothesis of market integration and price convergence (Coddington and Wang, 2003; Serletis, 1997; King and Cuc, 1996; NEB, 1995; Doane and Spulber, 1994). However, California's natural gas price rocketed from under $10 per million British thermal units (MMBTU) to over $60 per MMBTU during November 2000 – January 2001 (CEC, 2003), far more than the contemporaneous rise in the most actively traded spot gas market at Henry Hub, Louisiana. This California gas price spike is attributable to gas market dysfunction (FERC, 2003). Since the California electricity crisis that ended in June 2001, California's gas markets have been calm, with spot prices tracking Henry Hub's.

This appendix presents the empirical evidence to support E3's market-based forecast of California gas prices made under the following scenarios:

- If there is trading for gas futures and basis swaps futures,[120] the California gas price forecast is (a) the price of a California gas basis swaps futures contract plus (b) the price of Henry Hub gas futures contract.

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[120] NYMEX (http://www.nymex.com/jsp/markets/ng_oth_pgbdes.jsp) explains the "PG&E Citygate Basis Swap":

"The Pacific Gas & Electric Co. is one of the largest suppliers of natural gas in California, with a pipeline network that traverses the state from Oregon to Arizona. A subsidiary, California Gas Transmission (CGT), connects with British Columbia pipelines at the U.S.-Canadian border. The PG&E Citygate is any point at which the backbone transmission system connects to the local transmission and distribution system with connection points in northern, central, and southern California. The Citygate is not one specific, physical location, but is a 'virtual trading point' on the CGT system.

- Absent gas basis swaps futures trading, the California gas price forecast is the Henry Hub futures price.

6.4.2 Model

Market-based forecast and spot price regression

The market price that a gas buyer can readily obtain for gas delivered in California during a forecast period for which gas basis swap futures and gas futures are traded is

$$G = c + F, \tag{1}$$

where c = price of a California gas basis swaps futures contract (e.g., PG&E city gate); and F = price of a gas futures contract (\$/MMBTU) for Henry Hub delivery.

Equation (1) is consistent with a spot price regression that relates the California spot gas price P to the Henry Hub's spot gas price H and can be used in cross-hedging by a gas buyer or trader (Woo, Horowitz and Hoang, 2001):

$$P = \alpha + \beta H + \varepsilon. \tag{2}$$

"The volatility of natural gas prices has given rise to a basis market that is quoted as a differential to the price of the New York Mercantile Exchange, Inc., Henry Hub natural gas futures contract, which has evolved into the benchmark for forward natural gas markets industry-wide because of its liquidity and transparency.

"Managing this price differential is important to better help market participants offset their price risk in this major market center, the Exchange provides a PG&E Citygate natural gas basis swaps futures contract. The final settlement is equal to the bidweek price (average) for the PG&E citygate under the California heading found in the Natural Gas Intelligence bidweek survey minus the NYMEX Division Henry Hub natural gas futures contract final settlement price for the corresponding contract month.

"The lot size of 2,500 million Btus, multiplied by the number of calendar days in the month, represents a commonly traded market unit and is one-quarter the size of the Henry Hub futures contract, giving market participants additional flexibility in managing price risk. The contract is available for trading on the NYMEX ClearPortsm trading platform."

Here, α and β are coefficients to be estimated, and ε is a random-error term with zero mean and finite variance. The slope coefficient β measures the response of a California spot gas price to a \$1/MMBTU change in the Henry Hub spot price. When $\beta = 1$, the intercept α is the average difference between California and Henry Hub spot prices, which should not exceed the average cost of transportation.

Using equation (2), a gas buyer may cross-hedge his/her purchase cost per MMBTU by buying β MMBTU of gas futures at a price F, taking delivery, selling β MMBTU at H, and earning a profit of $\beta(H - F)$. The buyer's per-MMBTU cost becomes $[P - \beta(H - F)] = \alpha + \beta H + \varepsilon - \beta(H - F) = \alpha + \beta F + \varepsilon$, implying an expected cost of $(\alpha + \beta F)$.

If $(c + F) < (\alpha + \beta F)$, a gas trader's expected positive profit is $[(\alpha - c) + (\beta - 1) F]$ per MMBTU because the trader can buy gas basis swap futures at c and gas futures at F and sell California gas forward at $(\alpha + \beta F)$ to a gas buyer. Conversely, if $(c + F) > (\alpha + \beta F)$, a gas trader can cross-hedge the California spot gas price and sell gas basis swap futures and gas futures in NYMEX to earn an expected positive profit of $[(c - \alpha) + (1 - \beta) F]$ per MMBTU. Since expected positive profits cannot persist under active spot and futures trading, $c = \alpha$ and $\beta = 1$, which are two testable hypotheses that if not rejected by spot gas price data, would support our market-based approach to forecasting California gas price.

Partial adjustment

The spot price regression given by equation (2) assumes instantaneous adjustment: a \$1 spot price movement in the Henry Hub market immediately translates into \$$\beta$ price change in a

California market. Coddington and Wang (2003) report that it takes more than 3 days for the difference between the California and Henry Hub and spot prices to converge to the average transportation cost. Hence, we use a partial adjustment model (Kmenta, 1971, Chapter 11) to characterize the spot gas price regression.

Suppose the California market equilibrium price condition is

$$P_t^* \quad = \quad \alpha + \beta H_t + \varepsilon_t; \qquad (3)$$

where P_t^* = unobserved California equilibrium price on day t, H_t = Henry Hub price on day t, and ε_t = random error on day t. Under partial adjustment, the actual daily price adjustment is

$$(P_t - P_{t-1}) \quad = \quad \lambda\,(P_t^* - P_{t-1}),$$

where $0 \le \lambda \le 1$ is the extent of adjustment. If $\lambda = 0$, $P_t = P_{t-1}$ and the daily California prices do not adjust to changing market conditions. If $\lambda = 1$, $P_t = P_t^*$ so that the daily prices adjust instantaneously to achieve equilibrium. Finally, $(1/\lambda)$ is the speed of adjustment: the number of days required for the California market price to regain its equilibrium level after being perturbed by the Henry Hub price change or random events.

Algebraic substitution yields the estimable form of equation (3):

$$P_t \quad = \quad \theta + \gamma H_t + \phi P_{t-1} + \mu_t \qquad (4)$$

where $\theta = \lambda\alpha$, $\gamma = \lambda\beta$, $\phi = (1-\lambda)$, and $\mu_t = \lambda\varepsilon_t$.

Stochastic specification

For empirical implementation, we postulate that the error-term follows an autoregressive process of order k, AR(k): $\mu_t = \Sigma_j \rho_j \mu_{t-j}$ + white noise for j = 1, .., k (Davidson and MacKinnon, 1993, pp. 341-343). This specification allows for serial correlation likely present in the daily gas price series (Coddington and Wang, 2003).

We apply maximum likelihood (ML) method (PROC AUTOREG in SAS) to estimate equation (4) to avoid the potential bias caused by the possible correlation between P_{t-1} and μ_t (Kmenta, 1971, Chapter 11).

6.4.3 Data

The spot-price regression's dependent variable is the daily California volume-weighted average price for delivery at the PG&E city gate or Southern California Gas (SCG). Besides the intercept, the set of independent variables includes binary indicators for the California electricity and gas crises, the daily volume-weighted average price at the Henry Hub, and the lagged California average price. The crisis indicators isolate the price effect of these two unusual events characterized by extreme weather, capacity shortage, market power abuse, and falsely reported gas prices (Lee, 2004).

Table 44 presents the summary statistics for the three gas price series used in our estimation supplied by Platts, and pair-wise correlation between a California price and the Henry Hub price.. We recognize that the regression estimates can be spurious if the price series are random walks, since they may drift apart without limit over time (Davidson and McKinnon, 1993, pp. 669-673). To guard against this possibility, we compute the Augmented Dickey-Fuller (ADF) statistic to test the null hypothesis that a price series is a random walk. The critical value of the ADF statistic at the 5% significance level is –2.86.

Table 44: Summary and ADF statistics for three spot-gas price series

Period	PG&E Citygate price ($/MMBtu)				SoCal Gas price ($/MMBtu)				Henry Hub price ($/MMBtu)		
	Mean ($/MM Btu)	Std. ($/MM Btu)	ADF statistic	Cor-relation	Mean ($/MM Btu)	Std. ($/MM Btu)	ADF statistic	Correl-ation	Mean ($/MM Btu)	Std. ($/MM Btu)	ADF statistic
Full sample	4.19	3.46	-6.74*	0.73	4.01	4.07	-7.53*	0.70	3.27	1.57	-4.38*
Before the electricity crisis	2.49	0.38	-6.14*	0.70	2.37	0.46	-4.02*	0.92	2.35	0.48	-3.55*
During the electricity crisis	8.05	5.54	-4.25*	0.66	10.02	7.24	-4.28*	0.57	5.22	1.64	-1.58
After the electricity crisis	3.69	1.31	-2.53	0.95	3.68	1.30	-2.84	0.93	3.86	1.55	-4.08*

Note: "*" = "Significant at $p = 0.05$".

Table 44 shows:

- For the full sample, the California spot gas prices are higher and more volatile than and moderately correlated with the Henry Hub spot gas prices. The ADF statistics show that all three series do not follow a random walk.

- For the before-electricity-crisis period (prior to 05/01/00), the California spot gas prices are similar to the Henry Hub spot gas prices. The SCG gas prices are more correlated with the Henry Hub spot gas prices than PG&E city gate prices. The ADF statistics show that all three series do not follow a random walk.

- During the electricity crisis period (05/01/00 – 06/30/01), the California spot gas prices are much higher and more volatile than and poorly correlated with the Henry Hub spot gas prices. The ADF statistics show that the Henry Hub series follows a random walk.

- For the after-electricity-crisis period (since 07/01/01), the California spot gas prices are similar to and highly correlated with the Henry Hub spot gas prices. The ADF statistics show that the PG&E city gate and SCG series follow a random walk.

6.4.4 Results under AR(k) specification

PG&E city gate

Table 45 reports the PG&E city gate price regression with AR(1), AR(2), or AR(4) errors. With almost identical root-men-squared-errors, all three regressions explain 95+% of the PG&E city gate price variance. The likelihood (LLH) ratio test results and the Akaike information criterion (AIC) values indicate that the errors may follow an AR process of the fourth or higher order. With the exception of the intercept and the electricity crisis indicator and one AR parameter, all coefficient estimates are significant at the 5% level.

The sample period for PG&E city gate is 05/01/98-08/12/03, with 1929 daily observations. t-statistics in ( ) are for testing the null hypothesis that the coefficient is equal to zero. For the 5% significance level, the critical value for the t-statistic is 1.96, χ^2 at 1 degree of freedom 3.84, and χ^2 at 3 degrees of freedom is 7.81.

Table 45: Maximum likelihood estimation of PG&E city gate daily price regression under the partial adjustment specification with serially correlated errors.

Variable (coefficient estimate)	Coefficient estimates under alternative orders of autoregressive (AR) process		
	First order	Second order	Fourth order
Intercept (*f* = *la*)	0.0256 (0.34)	0.072 (0.64)	0.027 (0.50)
= 1, if electricity crisis (05/00 – 06/01); = 0, otherwise (k_1)	0.125 (1.20)	0.220 (1.44)	0.079 (1.07)
= 1, if gas crisis (11/00 – 05/01); = 0, otherwise (k_2)	1.024 (5.47)*	1.325 (4.67)*	0.696 (5.18)*
Henry Hub daily price (*g* = *lb*)	0.214 (7.00)*	0.276 (6.37)*	0.137 (6.10)*
Lagged PG&E Citygate daily price (*h* = 1- *l*)	0.779 (28.9)*	0.703 (14.2)*	0.856 (45.6)*
AR(1) parameter (r_1)	0.525 (14.0)*	0.534 (10.3)*	0.385 (14.2)*
AR(2) parameter (r_2)		0.138 (5.65)*	0.148 (5.90)*
AR(3) parameter (r_3)			0.009 (0.372)
AR(4) parameter (r_4)			-0.207 (-8.74)*
Root-mean-squared error	0.65	0.65	0.63
Total R-squared	0.96	0.96	0.97
Log-likelihood (LLH) at convergence	-1906.5	-1889.5	-1855.5
LLH ratio test of H_0: AR(1) against H_1: AR(j > 1): χ^2 statistic with d.f. = j-1		34*	68*
Akaike information criterion (AIC)	3825	3793	3729
ADF statistic for cointegration test of H_0: Regression residuals follow a random walk	-28.4*	-29.2*	-30.7*

Note: The sample period for PG&E city gate is 05/01/98-08/12/03, with 1929 daily observations. t-statistics in ( ) are for testing the null hypothesis that the coefficient is equal to zero. For the 5% significance level, the critical value for the t-statistic is 1.96, □^{2} at 1 degree of freedom 3.84, and χ^2 at 3 degrees of freedom is 7.81.

The coefficient estimates vary across the three AR specifications. However, irrespective of the of the AR specification, the estimates for ϕ are highly significant, rejecting the hypothesis of instantaneous adjustment.

To illustrate the sensitivity of coefficient estimates to AR specification, consider the estimate for $\lambda = (1-\phi)$, which is 0.221 under the AR(1) specification, 0.297 under the AR(2) specification, and 0.144 under the AR(4) specification. The corresponding number of days required for the PG&E city gate market to regain equilibrium is 4.5, 3.4, and 6.9, respectively. This small range of required days suggests that we can apply equation (3) to make a California price forecast for a relatively long period of 5 years or more.

The effect of the electricity and gas crises on the daily spot price ranges from \$(0.125 + 1.024) = \$1.15 per MMBTU for the AR(1) specification to \$(0.079 + 0.696) = \$0.775 per MMBTU for the AR(4) specification. At the market equilibrium, the effect is magnified by the estimate of $(1/\lambda)$ so that it is \$1.15/0.221 = \$5.2 per MMBTU for the AR(1) specification and \$0.775/0.144 = \$5.38 per MMBTU for the AR(4) specification. This large effect suggests that during the California electricity and gas crises, the PG&E city gate market disconnected from the Henry Hub market.

The ADF statistics for testing cointegration of PG&E city gate and Henry Hub prices show that the spot price regressions in Table 2A are not spurious as their residuals do not follow a random walk.

Table 45 suggests sensitivity of coefficient estimates to AR error specification. If this sensitivity extends to the estimates of (α, β) in the market equilibrium condition, it questions the validity of using cross-hedging to develop a gas price forecast. Hence, we test the hypothesis that (α, β) do not vary by AR error specification. If the data do not reject this hypothesis, we can safely conclude that the equilibrium price condition is robust, suitable for developing a market-based gas price forecast.

Table 46 presents the results of testing the following two null hypotheses: (1) the average difference between PG&E city gate-Henry Hub spot prices is zero (H_0: $\alpha = 0$), and (2) the PG&E city gate and Henry Hub spot gas prices move in perfect tandem (H_0: $\beta = 1$).[121] We cannot reject these two null hypotheses at the 5% level, irrespective of the AR specification.

Table 46: Results of testing of two null hypotheses for PG&E City Gate

Order of AR process	Basis differential (*a* in $/MMBtu)					Optimal hedge ratio (*b*)				
	Estimate	Standard error	Lower bound	Upper bound	t-stat. to test H_2: $\alpha = 0$	Estimate	Standard error	Lower bound	Upper bound	t-stat. to test H_1: $\beta = 1$
1	0.116	0.343	-0.556	0.788	0.339	0.972	0.098	0.781	1.163	-0.287
2	0.243	0.359	-0.461	0.947	0.676	0.931	0.111	0.713	1.148	-0.626
4	0.187	0.336	-0.472	0.847	0.557	0.948	0.105	0.744	1.153	-0.493

Note: Testing (1) the average difference between PG&E city gate and Henry Hub spot prices is zero (H_0: $\alpha = 0$), and (2) the PG&E city gate and Henry Hub spot gas prices move in perfect tandem (H_0: $\beta = 1$). The upper and lower bounds define the 95% confidence interval. The critical value for t-statistic at the 5% level is 1.96.

[121] Suppose $g = f(z)$ is the value of a non-linear function of z, the vector of coefficient estimates. The standard error of g is the square-root of $\partial g^T/\partial z \; \Sigma \; \partial g/\partial z$ where Σ = covariance matrix of z. The t-statistic for H_0: $\alpha = 0$ is (a / σ_a) where a = estimate of α, and σ_a = standard error of a. The t-statistic for H_0: $\beta = 0$ is (b / σ_b) where b = estimate of β, and σ_b = standard error of b.

4.2 Southern California Gas

Table 47 reports the SCG price regression with AR(1), AR(2), or AR(4) errors. With identical root-men-squared-errors, all three regressions explain 95+% of the SCG price variance. The LLH ratio test results and AIC values indicate that an AR error process of fourth or higher order. With the exception of the intercept, the electricity crisis indicator and two AR parameters, all coefficient estimates are significant at the 5% level.

The coefficient estimates vary across the three AR specifications. However, the estimates for ϕ are highly significant, decisively rejecting the hypothesis of instantaneous adjustment. The estimate for $\lambda = (1-\phi)$ is 0.450 under the AR(1) specification, 0.490 under the AR(2) specification, and 0.345 under the AR(4) specification. The corresponding number of days required for the California market to regain equilibrium is 2.2, 2.0, and 2.9, respectively. This range of required days is smaller than the one for the PG&E city gate price because the SCG is better inter-connected with the Henry Hub than the PG&E city gate.

Table 47 indicates the spot price effect of the electricity and gas crises is \$(0.674 + 2.801) = \$3.475 per MMBTU for the AR(1) specification to \$(0.425 + 2.317) = \$2.742 per MMBTU for the AR(4) specification. At the market equilibrium, the effect is \$3.475/0.45 = \$7.72 per MMBTU for the AR(1) specification and \$2.742 /0.345 = \$7.9 per MMBTU for the AR(4) specification. This large effect suggests that during the California electricity and gas crises, the SCG market separated from the Henry Hub market.

Table 47: Maximum likelihood estimation of SCG city gate daily price regression under the partial adjustment specification with serially correlated errors.

Variable (coefficient estimate)	Coefficient estimates under alternative orders of autoregressive (AR) process		
	First order	Second order	Fourth order
Intercept ($f = la$)	-0.102 (-0.79)	-0.087 (-0.61)	-0.108 (-1.00)
= 1, if electricity crisis (05/00 – 06/01); = 0, otherwise (k_1)	0.674 (3.05)*	0.800 (3.24)*	0.425 (2.23)*
= 1, if gas crisis (11/00 – 05/01); = 0, otherwise (k_2)	2.801 (8.85)*	2.912 (8.36)*	2.317 (6.66)*
Henry Hub daily price ($g = lb$)	0.480 (11.2)*	0.515 (11.6)*	0.377 (8.10)*
Lagged SoCal Gas daily price (h = 1- l)	0.550 (17.1)*	0.510 (13.2)*	0.655 (15.3)*
AR(1) parameter (r_1)	0.770 (30.0)*	0.823 (19.6)*	0.680 (15.0)*
AR(2) parameter (r_2)		-0.031 (-1.20)	-0.070 (-2.91)*
AR(3) parameter (r_3)			0.096 (4.02)*
AR(4) parameter (r_4)			-0.000 (-0.02)
Root-mean-squared error	0.71	0.71	0.71
Total R-squared	0.97	0.97	0.97
Log-likelihood (LLH) at convergence	-2794.5	-2793.5	-2784.5
LLH ratio test of H_0: AR(1) against H_1: AR(j > 1): χ^2 statistic with d.f. = j-1		2	18*
Akaike information criterion (AIC)	5601	5601	5587
ADF statistic for cointegration test of H_0:	-38.2*	-37.9*	-35.5*

Regression residuals follow a random walk			

Note: The sample for SCG is 07/02/96-0812/03 with 2597 observations. t-statistics in ( ) are for testing the null hypothesis that the coefficient is equal to zero. For the 5% significance level, the critical value for the t-statistic is 1.96, χ^2 at 1 degree of freedom 3.84, and χ^2 at 3 degrees of freedom is 7.81.

Finally, the ADF statistics for testing cointegration of SCG and Henry Hub prices show that the spot price regressions in Table 3A are not spurious as their residuals do not follow a random walk.

Since Table 47 suggests sensitivity of coefficient estimates to error specification, Table 48 tests if (α, β) vary by AR error specification. Table 48 shows that the equilibrium price condition is robust, suitable for developing a market-based gas price forecast.

Table 48: Results of testing of two null hypotheses for Southern California Edison

Order of AR process	Basis differential (a in \$/MMBtu)					Optimal hedge ratio (b)				
	Estimate	Standard error	Lower bound	Upper bound	t-stat. to test H_2: $\alpha = 0$	Estimate	Standard error	Lower bound	Upper bound	t-stat. to test H_1: $\beta = 1$
1	-0.227	0.289	-0.794	0.341	-0.783	1.067	0.085	0.900	1.234	0.786
2	-0.176	0.295	-0.754	0.403	-0.595	1.052	0.087	0.881	1.222	0.594
4	-0.315	0.326	-0.954	0.324	-0.966	1.095	0.097	0.906	1.285	0.985

Note: Testing (1) the average difference between SCG and Henry Hub spot prices is zero (H_0: $\alpha = 0$), and (2) the SCG city gate and Henry Hub spot gas prices move in perfect tandem (H_0: $\beta = 1$). The upper and lower bounds define the 95% confidence interval. The critical value for t-statistic at the 5% level is 1.96.

6.4.5 Conclusion

Natural gas market integration and price convergence since open access and deregulation in the mid-1980s suggest that California gas market prices should vary with those at the most active market of Henry Hub. Our investigation of the California and the Henry Hub spot prices yields the following findings:

A partial adjustment model explains the gas spot price movements in California.

- Under the AR specification, the spot price in excess of the normally expected level is \$5.2 - \$5.4 per MMBTU for PG&E City Gate delivery and \$7.7 to \$7.9 per MMBTU for SCG delivery, similar to \$4.18 per MMBTU and \$7.03 per MMBTU reported by FERC (2003).
- Except for the California electricity and gas crisis periods, the estimated difference between the California and Henry Hub spot prices is not significantly different from zero.
- At equilibrium, a \$1/MMBTU change in the Henry Hub price translates into a \$1/MMBTU change in the California price.

These findings lead us to conclude that there is trading for gas futures and basis swaps futures, the California gas price forecast is (a) the price of a California gas basis swaps futures contract plus (b) the price of Henry Hub gas futures contract. Absent gas basis swaps futures trading, the California gas price forecast is the Henry Hub futures price.

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